Wabash River Coal Gasification Repowering Project

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EXECUTIVE SUMMARY

The Wabash River Coal Gasification Repowering Project (WRCGRP, or Wabash Project) is a joint venture of Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana, who have jointly repowered an existing 1950's vintage coal fired steam generating plant with coal gasification combined cycle technology. The Project is located in West Terre Haute, Indiana at PSI's existing Wabash River Generating Station. The Project processes locally mined Indiana high sulfur coal to produce 262 megawatts of electricity.

PSI and Destec are participating in the Department of Energy Clean Coal Technology Program to demonstrate coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments. As a Clean Coal Round IV selection, the project will demonstrate integration of an existing PSI steam turbine generator and auxiliaries, a new combustion turbine generator, heat recovery steam generator tandem, and a coal gasification facility to achieve improved efficiency, reduced emissions, and reduced installation costs.

Reaching completion in 1995, the Project represents the largest coal gasification combined cycle power plant in the United States. Its design allows for lower emissions than other high sulfur coal fired power plants and resultant heat rate improvement of approximately 20% over the existing plant configuration.

Key objectives for 1997 centered primarily on meeting or exceeding contractual performance capacity while continuing to advance the technology through operational procedure development and equipment and engineering upgrades. Of those key objectives, several critical factors were identified for 1997. Those were:

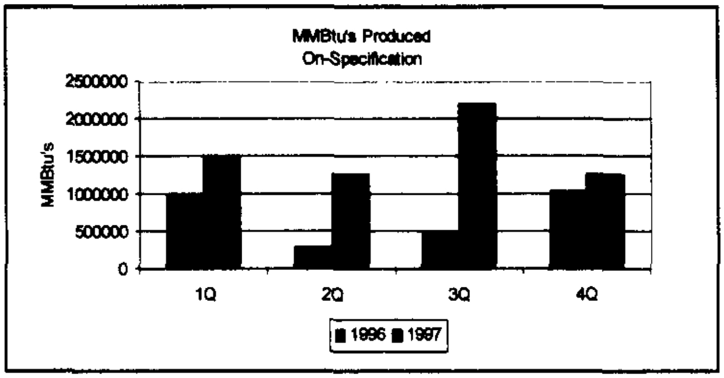
- Meet guarantee for proforma syngas production or better the contract capacity.

- Extend operational campaigns to 90 days through improvements in
  - Deposition control
  - Dry Char reliability

- Reduce the number of unplanned outages (a total of 51 were recorded for 1996) and reduce downtime hours attributable with each "area" of operations (Appendix D)

- Perform a successful alternate fuel test

- Reduce nitrogen consumption in the gasification process to match production within the Air Separation Unit.



1997 realized significant operational improvements when compared with 1996 in all areas of primary performance indicators. Produced and Delivered Capacity Factors increased 218% and 255%, respectively, over 1996. Syngas production increased 224% (chart at left) to over 6,214,000 MMBtu's and inlet coal usage increased 209% from the previous year. Of the unplanned trips off of coal operation (47 total), 33 were directly attributable to the gasification process. 25 of the 33 were due to mechanical difficulties in the process while 18 were directly attributable to instrumentation or electrical difficulties. The Combustion Turbine (CT) operated for over 3,700 hours on coal generated synthetic gas yielding an increase from 1996 production of over 227%. Total by-product sulfur production increased 269% with over 4,450,000 lbs produced compared to approximately 1,129,000 lbs in 1996. In addition to reaching these record production figures, the Wabash Project achieved several significant operational milestones in 1997, including:

- Successful swap to spare gasifier
- Improved dry char filtration through use of metal elements
- Installation of three (3) new heat exchangers to improve heating and cooling of dry char and catalyst systems during shutdown and startup
- Installation of improved wind proof pilots on flare system to improve reliability of continuous flame on flare
- Installation of new flare tip to reduce ambient noise during startup and/or emergency trips of the combustion turbine off of syngas
- Installation of 180 degree ell designed to improve flow and limit deposition from the gasifier second stage through the post resident vessel.
- Completed first operational run on an alternate fuel (petroleum coke) processing approximately 18,000 tons of petcoke while operating approximately 221 hours.
- Gasification plant operated on coal 3,885 hours producing 6,214,864 MMbtu's of syngas.
- Combustion turbine operated on syngas for 3,701 hours.
- Completion of the first comprehensive environmental testing of the facility while operating on-coal with maximum power output (second quarter). (See Appendix E).

Major milestones and activities projected for 1998 include evaluation of the new project installations, performance monitoring of the Dry Char Recovery System filtration efficiency, continued focus on gasifier operations and continued demonstration of the commercial viability of the project.

INTRODUCTION

In September 1991 the United States Department of Energy (DOE) selected the Wabash River Coal Gasification Repowering Project (WRCGRP) for funding under the Round IV of the DOE's Clean Coal Technology Program. This was followed by nine months of negotiations and a congressional review period. The DOE executed a Cooperative Agreement on July 28, 1992. The project's sponsors, PSI Energy, Inc., and Destec Energy, Inc., will demonstrate, in a fully commercial setting, coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments (CAAA). The project will also demonstrate important advances in Destec's coal gasification process for high sulfur bituminous coal. After receiving the necessary state, local and federal approvals, this project began construction in the third quarter of 1993 and commercial operations in the third quarter of 1995. This facility has a planned three-year demonstration period and 22 year operating period (25 years total).

The Wabash River Coal Gasification Repowering Project is a joint venture of Destec and PSI Energy, who have developed, designed, constructed, own and now operate a coal gasification facility and a combined cycle (CGCC) power plant (respectively). Coal gasification technology, originally developed by The Dow Chemical Company and owned by Destec, was used to repower Unit 1 of PSI's Wabash River Generating Station in West Terre Haute, Indiana. The CGCC power plant produces a nominal 262 net megawatts (MWe) of clean, energy efficient capacity for PSI's customers. In the repowered configuration, PSI and its customers can additionally benefit because this project can enhance PSI's compliance plan under the CAAA regulations. The project utilizes locally mined high sulfur coal and represents the largest CGCC power plant in operation in the United States. This plant is also designed to emit significantly lower emissions than most other high sulfur coal fired power plants.

BACKGROUND INFORMATION

Project Inception and Objectives

Public Law 101-121 provided $600 million to conduct cost-shared Clean Coal Technology (CCT) projects to demonstrate technologies that are capable of replacing, retrofitting, or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued by the Department of Energy in January 1991, soliciting proposals to demonstrate innovative energy efficient technologies that were capable of being commercialized in the 1990's. These technologies were to be capable of: (1) achieving significant reductions in the emissions of sulfur dioxide and/or nitrogen oxides from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or; (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, 33 proposals were received by the DOE in May 1991. After evaluation, nine projects were selected for award. These projects involved both advanced and pollution control technologies that can be "retrofitted" to existing facilities and "repowering" technologies that not only reduce air pollution but also increase generating plant capacity and extend the operating life of the facility.

One of the nine projects selected for funding is the project proposed by the Wabash River Coal Gasification Repowering Project Joint Venture. This proposal (a Joint Venture between Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana) requested financial assistance from DOE for the design, construction, and operation of a nominal 2500 ton-per-day (262 MWe) two-stage, oxygen-blown, coal gasification combined cycle (CGCC) repowering demonstration project. The project, named the Wabash River Coal Gasification Repowering Project, is located at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The project location and site are shown in Figures 1, 2, 3, and 4. The demonstration project utilizes advanced coal gasification technology in a commercial repowering setting to repower an existing generating unit affected by the Clean Air Act Amendments of 1990. Sulfur emissions from the repowered generating unit will be reduced by greater than 90%, while at the same time increasing electrical generating capacity over 150%. The project, including the demonstration phase, will last 79 months. The DOE's share of the project cost will be $219 million.

<u>The CGCC system consists of:</u> (See Figures 5 & 5A)

- Destec's oxygen-blown, entrained flow, two stage coal gasifier, which is capable of utilizing high sulfur bituminous coal;
- An air separation unit;
- A gas conditioning system for removing sulfur compounds and particulate;
- Systems or mechanical devices for improved coal feed and all necessary coal handling equipment;
- A combined cycle power generation system wherein the gasified coal syngas is combusted in a combustion turbine generator;
- A heat recovery steam generator.

The result of repowering is a CGCC power plant with low environmental emissions (SO_2 of less than 0.25 lbs/MMbtu and NO_x of less than 0.1 lb/MMbtu) and high net plant efficiency. The repowering increases unit output, providing a total CGCC capacity of nominal 262 MWe. The Project demonstrates important technological advancements in processing high sulfur bituminous coal.

In addition to the joint venture members, PSI and Destec, the Phase II project team included Sargent & Lundy, who provided engineering services to PSI, and Dow Engineering, who provided engineering services to Destec.

The potential market for repowering with the demonstrated technology is large and includes many existing utility boilers currently fueled by coal, oil, or natural gas. In addition to greater, more cost effective reduction of SO_2 and NO_x emissions attainable by using the gasification technology, net plant heat rate is improved. This improvement is a direct result of the combined cycle feature of the technology, which integrates a combustion topping cycle with a steam bottoming cycle. This technology is suitable for repowering applications and can be applied to any existing steam cycle located at plants with enough land area to accommodate coal handling and storage and the gasification and power islands.

One of the project objectives is to advance the commercialization of coal gasification technology. The electric utility industry has traditionally been reluctant to accept coal gasification technology and other new technologies as demonstrated in the U.S. and abroad because the industry has no mechanism for differentiating risk/return aspects of new technologies. Utility investments in new technologies may be disallowed from rate-base inclusion if the technologies do not meet performance expectations. Additionally, the rates of return on these are regulated at the same level as established lower risk technologies. Therefore, minimal incentives exist for the utility to invest in, or develop, new technologies. Accordingly, most of the risk in new technologies has traditionally been assumed by the supplier.

The factors described above are constraints to the development of, and demand for, clean coal technologies. Constraints to development of new technologies also exist on the supply side. Developers of new technologies typically self-finance or obtain financing for projects through lenders or other equity investors. Lenders will generally not assume performance and operational risks associated with new technology. The majority of funds available from lending agencies for energy producing projects are for technologies with demonstrated histories in reliability, maintenance costs and environmental performance. Equity investors who invest in new energy technologies also seek higher returns to accept risk and often require the developer of the new technology to take performance and operational risks.

Consequently, the overall scenario results in minimum incentives for commercial size developments of new technologies. Yet without the commercial size test facilities, the majority of the risk issues remain unresolved. Addressing these risk issues through utility scale demonstration projects is one of the primary objectives of DOE's Clean Coal Technology Program.

The Wabash River Coal Gasification Repowering Project was developed in order to demonstrate the Destec Coal Gasification Technology in an environment, and at such a scale, as to prove the commercial viability of the technology. Those parties affected by the success of this Project include the coal industry, electric utilities, ratepayers, and regulators. Also, the financial community, who provides the funds for commercialization, is keenly interested in the success of this project. Without a demonstration satisfying all of these interests, the technology will make little advancement. Factors of relevance to further commercialization are:

- The Project scale (262 MWe) is compatible with all commercially available advanced gas turbines and thus completely resolves the issue of scale-up risks.

- The operational term of the Project is expected to be approximately 25 years including the DOE demonstration period of the first 3 years. This should alleviate any concerns that the demonstration does not define a fully commercial plant from a cost and operational viewpoint.

- The Project dispatches on a utility system and is called upon to operate in a manner similar to other utility generating units.

- The Project operates under a service agreement that defines guarantees of environmental performance, capacity, availability, coal to gas conversion efficiency and maximum auxiliary power consumption. This agreement serves as a model for future commercialization of the Destec Coal Gasification Technology and defines the fully commercial nature of the Project.

- The Project is designed to accommodate most coals available in Indiana and typical of those available to Midwestern utilities, thereby enabling utilities to judge fuel flexibility. The Project also enables testing of varying coal types on support of future commercialization of the Destec Coal Gasification Technology.

Plant Description

The Wabash River Coal Gasification Repowering Project Joint Venture participants developed and separately designed, constructed, own, and currently operate the syngas and power generation facilities making up the CGCC facility. Coal Gasification technology owned by Destec, is used to repower one of six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The Project will operate under a 25 year contact. In the repowered configuration, PSI and its customers additionally benefit because of the role the Project plays in PSI's Clean Air Act compliance plan. The CGCC power plant produces 262 MWe of clean, energy efficient, cost effective capacity for PSI's customers. An additional economic benefit of the State of Indiana is that the project not only represents the largest CGCC power plant in operation, but also emits lower emissions than other large, high sulfur coal fired power plants.

The gasification process can be described in the following manner: (see Figures 6 and 7): Coal is ground with water to form a slurry and then pumped into a gasification vessel where oxygen is added to form a hot, raw gas through partial combustion. Most of the non-carbon material in the coal melts and flows out the bottom of the vessel as slag (a black, glassy, non-leaching, sand-like material). The hot, raw gas is then cooled in a heat exchanger to generate high-pressure steam. Particulates, sulfur, and other impurities are removed from the gas to make acceptable fuel for the gas turbine. The gasification process by-products, sulfur and slag, will be sold thus mitigating the waste disposal problems of competing technologies.

The synthetic fuel gas (syngas) is piped to a combustion turbine generator, which produces approximately 192 MWe of electricity. A heat recovery steam generator recovers gas turbine exhaust heat to produce high-pressure steam. This steam and the steam produced in the high temperature heat recovery unit (HTHRU) in the gasification process supply an existing steam turbine generator in PSI's plant to produce an additional 104 MWe. The net plant heat rate for the entire new and repowered unit is approximately 9,000 Btu/kWh (Higher Heating Value or HHV), representing an improvement of approximately 20% over the existing unit. The project heat rate is among the lowest of commercially operated coal fired facilities in the United States.

The Destec Coal Gasification process was originally developed by The Dow Chemical Company during the 1970's in order to diversify its fuel base. The technology being used at Wabash is an extension of the experience gained from pilot plants and the full-scale commercial facility, Louisiana Gasification Technology, Inc., (LGTI) which operated from April 1987 until November 1995.

In order to generate data necessary for commercialization, the Joint Venture has chosen a very ambitious approach for incorporation of novel technology in the project. This approach is supported by PSI's desire to have another proven technology alternative available for future repowering or new base load units. Destec desires to enhance its competitive position relative to other clean coal technologies by demonstrating new techniques and process enhancements as well as gain information about operating cost and performance expectations. The incorporation of novel technology in the project will enable utilities to make informed commercial decisions concerning the utilization of Destec's technology, especially in a repowering application.

New enhancements, techniques and other improvements included in the novel technology envelope for the project are as follows:

- **A novel application** of integrated coal gasification combined cycle technology will be demonstrated at the project for the first time – **repowering of an existing coal fired power generating unit.**

- The **coal fuel** for the project **is high sulfur bituminous coal**, thus demonstrating the environmental performance and energy efficiency of Destec's advanced two-stage coal gasification process. Previous Destec technology development has focused on lower rank, more reactive coals.

- **Hot/Dry particulate removal/recycle will be demonstrated at full commercial scale** by the project. Destec's plant, LGTI, utilized a wet scrubber system to remove particulates from the raw syngas.

Other coal gasification process enhancements included in the project to improve the efficiency and environmental characteristics of the system are as follows:

- **Syngas Recycle** provides fuel and process flexibility while maintaining high efficiency.

- **A High Pressure Boiler** cools the hot, raw gas by producing steam at a pressure of 1,600 pounds per square inch absolute (psia).

- **The Carbonyl Sulfide (COS) Hydrolysis** system incorporated at the project is Destec's first application of this technology. This system is necessary to attain the high percent removal of sulfur at the project.

- **The Slag Fines Recycle** system recovers most of the carbon present in the slag by-products stream and recycles it back for enhanced carbon conversion. This also results in a high quality slag by-product.

- **Fuel Gas Moisturization** is accomplished at the project by the use of low level heat in a concept different from that used by Destec before. This concept reduces the steam injection required for nitrous oxide (NO_x) control in the combustion turbine.

- Sour water, produced by condensation as the syngas is cooled, is processed differently from the method used at LGTI. This novel **Sour Water System**, used at the project, allows more complete recycling of this stream, reducing waste water and increasing efficiency.

- An oxygen plant producing **95 percent pure oxygen** is used by the project. This increases the overall efficiency of the project by lowering the power required for production of oxygen.

- The **power generation facilities** included in the project incorporates the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the existing Unit 1 steam turbine.

- The project incorporates an **Advanced Gas Turbine** with a new design compressor and higher-pressure ratios.

- **Integration between the Heat Recovery Steam Generator (HRSG) and the Gasification Facility** has been optimized at the project to yield higher efficiency and lower operating costs.

- **Repowering of the Existing Steam Turbine** involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle will be utilized.

The gasification/repowering approach offers the following advantages as compared to other options:

- This is a viable alternative that will add life to existing older units. The primary assumption, however, is that reasonable life exists in the steam turbine to be repowered. If reasonable life exists in the steam turbine, the approach eliminates the need for refurbishment of much of the high wear components of conventional pulverized coal units. Three such items are the boiler, coal pulverizers and high energy piping systems.

- This approach is an alternative for Clean Air Act compliance compared with the traditional scrubber approach. Although space constraints are similar for the installed facility, waste storage requirements are smaller due to salable by-products in lieu of onsite storage of scrubber sludge.

- This approach provides a use for high sulfur coal. This is particularly important in areas such as Indiana where high sulfur coal is abundant and provides a substantial employment base.

Project Management

The WRCGRP Joint Venture established a Project Office for the execution of the project. The Project Office is located at Destec's corporate offices in Houston, Texas. All management, reporting, and project reviews for the project are carried out as required by the Cooperative Agreement. The Joint Venture partners, through a Joint Venture Agreement, are responsible for the performance of all engineering, design, construction, operation, financial, legal, public affairs, and other administrative and management functions required to execute the project. A Joint Venture Manager has been designated as responsible for the management of the project. A Joint Venture organization chart is shown as Figure 8. The Joint Venture Manager is the official point of interface between the Joint Venture and the DOE for the execution of the Cost Sharing Cooperative Agreement. The Joint Venture Manager is responsible for assuring that the Project is conducted in accordance with the cost, schedule, and technical baseline established in the Project Management Plan (PMP) and subsequent updates.

Major Activities and Milestones

The Project Cooperative Agreement was signed on July 28, 1992, with an effective date of August 1, 1992. Under the terms of the Cooperative Agreement, Project activities are divided into three phases:

- Phase I Engineering and Procurement
- Phase II Construction and Startup
- Phase III Demonstration

In addition, for purposes of the Cooperative Agreement, the Project is divided into three sequential Budget Periods. The expected duration of each budget period is as follows:

- Budget Period 1 — 10 months
- Budget Period 2 — 27 months
- Budget Period 3 — 39 months

The Project Milestone Schedule is provided in Figure 9.

Phase I Activities – Engineering and Procurement

Under the provisions of the Cooperative Agreement, the work activity in Phase I (engineering and procurement) focused on detailed engineering of both the syngas and power plant elements of the project which included design drawings, construction specifications and bid packages, solicitation documents for major hardware and the procurement. Site work was undertaken during this time period to meet the overall construction schedule requirements. The Project Team includes all necessary management, administrative and technical support.

The activities completed during this period were those necessary to provide the design basis for construction of the plant, including capital cost estimates sufficient for financing, and all necessary permits for construction and subsequent operation of the facility.

The work during Phase I can be broken down into the following main areas:

- Project Definition Activities
- Plant Design
- Permitting and Environmental Activities

Each of these activities is briefly described below. All Phase I activities were complete by 1993.

Project Definition Activities

This work included the conceptual engineering to establish the project size, installation configuration, operating rates and parameters. Definition of required support services, all necessary permits, fuel supply, and waste disposal arrangements were also developed as part of the Project Definitions Activities. From this information the cost parameters and projects economics were established (including capital costs, project development costs and operation and maintenance costs). Additionally, all project agreements necessary for construction of the plant were concluded. These include the cooperative agreement and the gasification services agreement.

Plant Design

This activity included preparation of design and major equipment specifications along with plant piping and instrumentation diagrams (P&ID's), process control releases, process descriptions, and performance criteria. These were prepared in order to obtain firm equipment specifications for major plant components, which established the basis for detailed engineering and design.

Permitting and Environmental Activities

During Phase I, applications were made and received for the permits and environmental activities necessary for the construction and subsequent operation of the project. The major project permits included:

- Indiana Utility Regulatory Commission – The state authority reviewed the project (under a petition from PSI for a Certificate of Necessity) to ensure the project will be beneficial to the state and PSI ratepayers. The technical and commercial terms of the project were reviewed in this process.

- Air Permit – This permit details the allowable emission levels for air pollutants from the project. It was issued under standards established by the Indiana Department of Environmental Management (IDEM) and the Environmental Protection Agency (EPA) Region V. This permit also included within it the authority to commence construction.

- NPDES Permit – This permit details and controls the quality of waste water discharge from the project. It was reviewed and issued by the Indiana Department of Environmental Management. For this project it will be a modification of the existing permit for PSI's Wabash River Generating Station.

- NEPA Review – The National Environmental Policy Act review was carried out by the DOE based on project information provided by the participants. The scope of this review is comprehensive in addressing all environmental issues associated with potential project impacts on air, water, terrestrial, quality, health and safety, and socioeconomic impacts.

Miscellaneous permits and approvals necessary for construction and subsequent operation of the project included the following.

- FAA Stack Height/Location Approval
  Controlling Authority: Federal Aviation Administration

- Industrial Waste Generator
  Controlling Authority: Indiana Department of Environmental Management

- Solid Waste

- FCC Radio License

- Spill Prevention Plan

- Wastewater Pollution Control Device Permit
  Controlling Authority: IDEM

<u>Phase II Activities – Construction</u>

Construction activities occurred in Phase II and included the necessary construction planning and integration with the engineering and procurement effort. Planning the construction of the project began early in Phase I. Separate on-site construction staffs for both Destec and PSI were provided to focus on their respective work for each element of the Project. Construction personnel coordinated the site geotechnical surveys, equipment delivery, storage and lay down space requirements. The construction activities included scheduling, equipment delivery, erection, contractors, security and control.

The detail design phase of the project includes engineering, drawings, equipment lists, plant layouts, detail equipment specifications, construction specification, bid packages and all activities necessary for construction, installation, and startup of the project.

Performance and progress during this period was monitored in accordance with previously established baseline plans. There were no Phase II activities conducted during this period.

Phase III Activities – Demonstration Period

Phase III consists of a three year demonstration period. The operation effort for the project began with the development of the operating plan including integration with the early engineering and design work of the project. Plant operation input to engineering was vital to assure optimum considerations for plant operations and maintenance and to assure high reliability of the facilities. The operating effort continued with the selection and training of the operating staffs, development of the plant operations manuals, the coordination of the startup with the construction crew, planning and execution of plant commissioning, the conduct and documentation of the plant acceptance test and continued operation and maintenance of the facility throughout the demonstration period.

Phase III activities are intended to establish the operational aspects of the project in order to prove the design, operability and longevity of the plant in a fully commercial utility environment.

Budget Periods

For ease of administration, the Project is divided into three subsequent budget periods with expected durations of:

- Budget Period 1 — 9 months
- Budget Period 2 — 26 months
- Budget Period 3 — 39 months

Budget Period 1 activities include pre-DOE award and project definition tasks, preliminary engineering work, and permitting activities. Budget Period 2 activities include detailed engineering, procurement, construction, pre-operations training tasks, and startup. Budget Period 3 activities include the three-year demonstration period. The budget period costs were originally projected and revised as follows:

	Original	Revised
Budget Period 1 DOE Share	$43,175,801	$21,864,591
Budget Period 2 DOE Share	$102,523,632	$144,934,842
Budget Period 3 DOE Share	$52,300,567	$52,300,567
Total	$198,000,000	$219,100,000

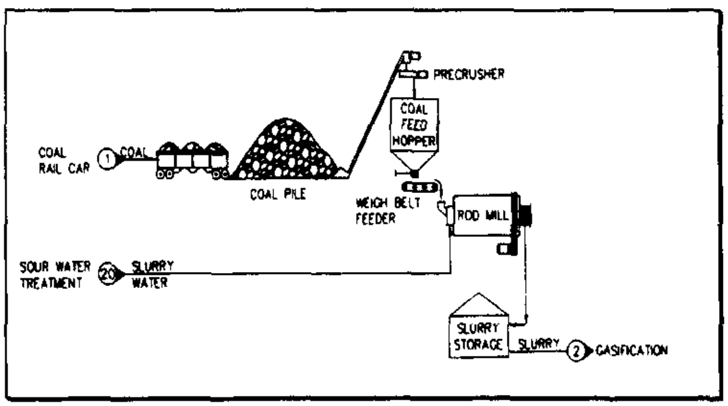
ACTIVITIES DURING 1997

A current Project schedule, indicating milestone dates and current status, is provided as Figure 10.

1997 Phase III Activities – Demonstration Period

The plant processes are broken down by area to better describe the activities during 1997 and focus on the accomplishments and areas identified as "opportunities for improvement". Each area is preceded by a graphic representation of the process along with a general process description.

COAL PREPARATION AND SLURRY AREA



The diagram at left depicts the process of coal slurry preparation. PSI has the responsibility of delivering coal and transporting it to the feed hopper. Coal enters the feed hopper then is fed to the rod mill via a weigh belt feeder. In 1997 all of the coal processed originated from the Hawthorne mine in Indiana. The coal is mixed with limestone (less than 3%) at the mine site, which is added as a fluxing agent to enhance slag flow characteristics in the gasifier. Treated water recycled from other areas of the gasification process is added to the coal at a controlled rate to produce the desired slurry solids concentration of approximately 62%. The use of a wet rod mill reduces potential fugitive particulate emissions from the grinding operations. Collection and reuse of water within the gasification process minimizes water consumption and effluent wastewater volume.

The slurry is then stored in an agitated tank, which is sufficiently large to supply the gasifier needs during forced rod mill outages. Most expected maintenance requirements of the rod mill and storage tank can be accomplished without interrupting gasifier operation.

All tanks, drums, and other areas of potential atmospheric exposure of the product slurry or recycle water are covered and vented into the tank vent collection system for vapor emission control. The entire slurry preparation facility is paved and curbed to contain spills, leaks, wash down, and rain water. All runoff will be carried by a trench system to a sump where it will be pumped into the recycle water storage tank to be reused in the coal slurry preparation system.

Primary coal characteristics, which effect operation of the gasifier include the following:

- Ash Content
- Sulfur
- Carbon
- Hydrogen
- Nitrogen
- Oxygen

The following table illustrates the average values for these constituents in 1997 while also outlining the variability that was encountered during the year:

Constituent	Average	High	Low
Ash, %	12.93	13.92	10.6
Sulfur, %	2.57	2.88	2.11
Carbon, %	70.15	73.96	55.18*
Hydrogen, %	4.84	5.01	3.92
Nitrogen, %	1.32	1.7	.91
Oxygen, %	8.13	11.26	6.64

*Single analysis of a single coal shipment received by PSI and is not to be consider normal or of statistical significance.

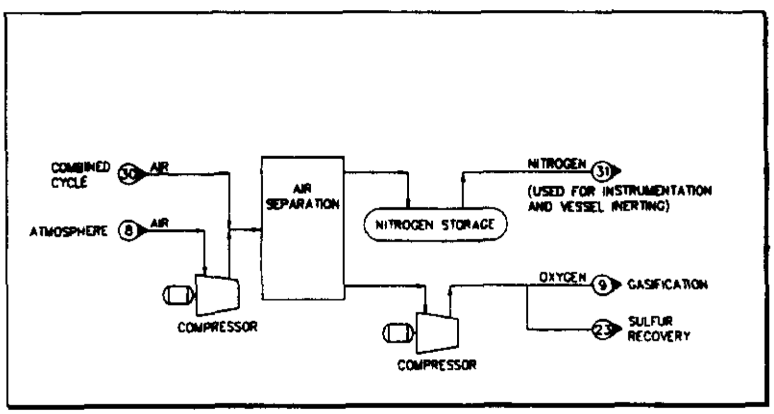
The rod mill is designed to crush the coal to a desired particle size to ensure stable "slurryability" and optimum carbon conversion in the gasifier. Continuous operation during production gradually decreases the diameter of the rods, which eventually effects particle size distribution. Particle size is strictly an optimization tool and does not dictate overall plant operation. During the first quarter of 1997, additional rods were added to the rod mill to facilitate proper particle size distribution. This was the first rod addition to the mill since beginning operation in 1995 after approximately 2000 hours of operation. This rod charge was not considered outside of the design equipment life of the rods based on grindability and makeup of the coal. The primary problems encountered in this area in 1997 centered around the foreign material in the coal which created excessive rod mill wear and tear, especially on the trommel screen, which is designed to prevent oversized particles and debris from entering the coal slurry feed tank. During the second quarter of the year an excessive quantity of oversized limestone and other foreign material (e.g. metal objects) entered the mill causing an excess of large particles in the slurry (objects that lodge themselves between the rods during milling creates ineffective crushing of the coal). This foreign material created a hole in the trommel screen allowing the oversized foreign material to pass to the slurry storage tank. This material eventually ended up partially plugging the check valves to the slurry feed pumps resulting in a plant shutdown due to fluctuations in slurry feed to the gasifier. Fluctuations in slurry feed created slag flow problems in the gasifier, which eventually led to plugging of the taphole. Foreign material in the coal continued to be a problem in the third quarter, which prompted discussions of this problem with the mine operators. It appears, through mining/blending operations and coal handling upgrades (magnetic separators on the belt feeder), that the situation has been resolved. There were no further problems realized in this area during the fourth quarter.

In 1997 a total of over 387,000 tons of coal was processed through the rodmill. An additional 18,000 tons of petroleum coke (petcoke) was also processed during a trial run late in the fourth quarter. Slurry fed from the slurry feed tank to the gasifier accounted for approximately 8,910,111 MMBtu's based on the average Btu value (dry) of the Hawthorne coal of 12,652 Btu/lb with petcoke having an average Btu value (dry) of 15,353 Btu/lb . Minor constituent concentrations in the slurry can be found in Table 2-9 (Coal Slurry Analysis Summary) in Appendix E – Environmental Testing.

Petroleum coke constituents, while having a higher Btu value and lower ash content than Hawthorne coal, had to be blended with coal generated slag to enhance slag flow characteristics (coal generated slag was used as a fluxing agent). Its effect on gasifier operation will be discussed later in this report. The average value for the primary constituents (dry basis) in petcoke are illustrated below:

Constituent	Average	High	Low
Ash, %	0.52	0.75	0.39
Sulfur, %	5.17	5.27	5.05
Carbon, %	87.49	89.03	82.52
Hydrogen, %	2.74	3.08	2.49
Nitrogen, %	0.99	1.05	0.93
Oxygen, %	3.08	3.19	1.15

AIR SEPARATION UNIT (ASU)



The Air Separation Unit (ASU), depicted at left, contains: an air compression system; an air purification and cryogenic distillation system; an oxygen compression system; and a nitrogen storage and handling system. Atmospheric air is compressed in a centrifugal machine then cooled in a chiller tower to approximately 40 degrees F. The cooled air is then purified through molecular sieve absorbers where atmospheric contaminants (H_2O, CO_2, hydrocarbons, etc.) are removed to prevent contaminants from freezing during cryogenic distillation. The dry, carbon dioxide-free air is separated into 95% purity oxygen, high purity nitrogen, and waste gas in the cryogenic distillation system (cold box). The gaseous oxygen is compressed in a six-stage centrifugal compressor and fed to the gasifier. Liquid nitrogen is also produced in the cold box with a portion being vaporized for use as gaseous nitrogen in the gasification system and the balance being liquefied and stored for use during ASU plant outages.

In 1996, the facility identified a shortcoming in the production of nitrogen when matched with typical nitrogen demand. It was noted, especially during start-up operations, that supplemental nitrogen had to be brought in, via truck, to facilitate start-up of the gasification island. In 1997, operational procedures were carefully checked and high end users were identified to help optimize the balance of nitrogen production versus consumption. Several key areas were identified as possible high end users. Those were:

- .. the heat up process utilized by the dry char filtration system and the heat up of the Carbonyl Sulfide (COS) catalysis process (due to the inherent need to keep these systems oxygen free to prevent exothermic reactions from occurring in the COS beds and to limit corrosive activity in the dry char filtration system). Corrective measures included the installation of three new heat exchangers, which improved COS catalyst heat-up time. Nitrogen piping was also installed to the dry char system to facilitate faster thermal cycles and to increase the efficiency of the heat up process by allowing nitrogen recycle versus the previous once-through system.

- .. nitrogen purges utilized to clear camera sight paths and for equipment purges during the start-up process.

By focusing on these two critical areas, significant strides were made in 1997 to limit external deliveries of nitrogen and to optimize plant production. By the end of the year, significant reductions had taken place and nitrogen demand had been closely matched to nitrogen production. Deliveries of external nitrogen decreased from a 1997 high of 15 trucks per month (9 million standard cubit feet) down to two trucks per month (1.2 million standard cubic feet). Efforts will continue in 1998 to ensure that this trend continues and improves where opportunities exist.

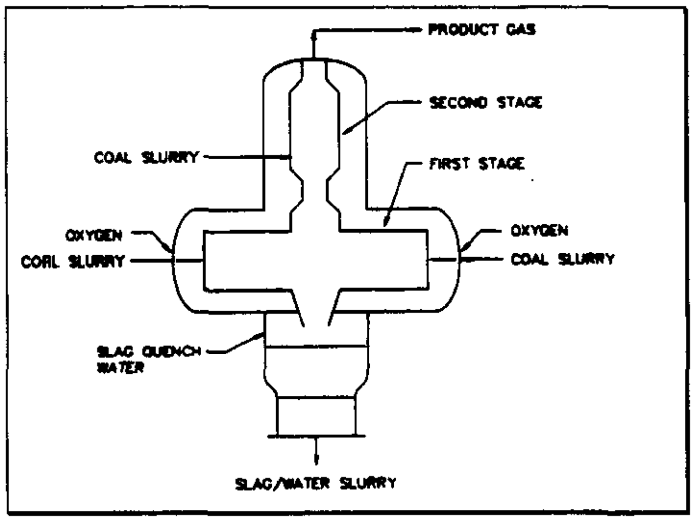
Oxygen production was sufficient during 1997 to meet the demands of the gasification island. Total production was approximately 328,000 tons for 1997 and product matched the purity requirements identified above. Several trips of the main air compressor during 1997 led to shut down of the gasification process due to the inability of the plant to produce oxygen for burner consumption (there is no oxygen storage capability at the facility). The first, in the second quarter of 1997, was due to an electrical design flaw in the ancillary systems of the main air compressor. It appeared, after careful investigation, that several of the ancillary systems were not adequately fuse protected. Therefore, when an over-amperage condition occurred on one of the auxiliary pieces of equipment it was sufficient to trip the main circuit breaker for the main air compressor. Corrective action included inspection of over 400 fuses to identify correct amperage requirements. Those fuses identified as being inadequate were replaced with correct fuses. During the third quarter, a loose fuse resulted in the failure of an oxygen vent valve, which subsequently tripped the main air compressor and the gasification process. It is suspected that the fuse was not properly seated after the inspection/replacement, which occurred during the second quarter. All fuses were rechecked to prevent recurrence of this problem.

A potential preventative maintenance issue was identified when, in December, the alternate oxygen pump suffered a failure of the lower impeller shaft bearing. Dynegy and manufacturer personnel worked together to identify a new lower impeller design which will be installed during the next available shutdown in 1998.

Additional upgrades to the oxygen plant during 1998 included the following:

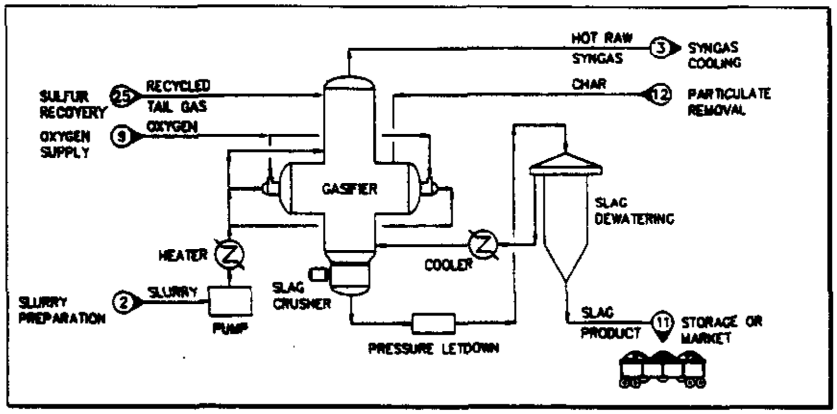
- A lube oil system upgrade was made to facilitate oil changes to the main air compressor.
- The main air compressor guide vanes (all stages) were put on a more aggressive preventative maintenance schedule due to a second stage failure in December.

GASIFICATION AND SLAG HANDLING

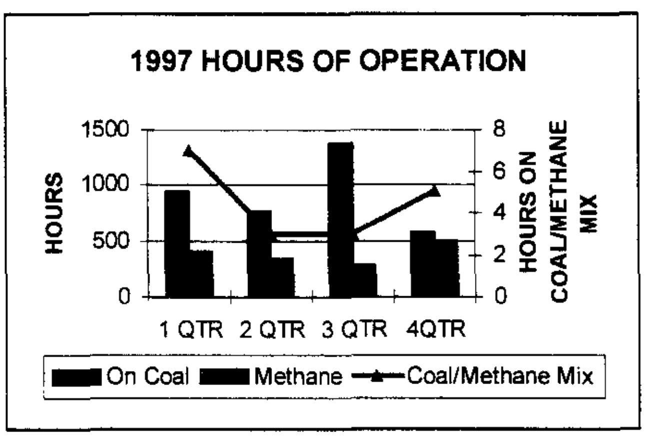


The Destec gasifier consists of two stages; a slagging first stage, and an entrained flow, non-slagging second stage. The first stage is a horizontal, refractory lined vessel in which coal slurry and oxygen are combined in partial combustion quantities at an elevated temperature (nominally 2500 degrees F) and pressure (400 psia). Dry particulate (char) filtered from the raw sygnas downstream of the gasifier is also recycled to the first stage gasification process. The oxygen and coal slurry are fed to the gasifier and atomized through two opposing mixing nozzles once the vessel has been adequately preheated. Natural gas is utilized for preheating the gasifier. No product syngas is generated for PSI's consumption during the pre-heat process while in methane operations. Oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point, thereby ensuring good slag removal. Produced synthetic gas (syngas) consists primarily of hydrogen, carbon dioxide, carbon monoxide and water vapor. Sulfur in the coal is converted primarily to hydrogen sulfide with a portion converted to carbonyl sulfide. Both sulfur species are processed down stream and are removed from the process. Mineral matter in the coal forms a molten slag. The second stage is a vertical refractory lined section in which additional coal slurry is reacted with the hot syngas stream exiting the first stage. This additional slurry serves to lower the temperature of the gas exiting the first stage to 1900 degrees F by vaporization of the slurry and endothermic reactions. The coal undergoes de-volatilization and pyrolysis thereby generating more gas at a higher heating value. No additional oxygen is added in the second stage. The partially reacted coal (char) and entrained ash is carried overhead with the gas.

Slag flows continuously through the tap hole of the first stage into the water quench bath, located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This process of continuous slag removal is compact; minimizes overall height of the gasifier structure; eliminates the high-maintenance requirements of problem prone lock hoppers; and completely prevents the escape of raw gasification products to the atmosphere during slag removal.



The slag slurry leaving the pressure let down system flows into a de-watering bin. The bulk of the slag will settle out in this bin, while the water overflows a weir at the top of the bin to a settler in which the slag fines are settled and removed. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. De-watered slag is loaded into a truck or rail car for transport to market or its storage/disposal site located on the south end of the Wabash River Generating station. The fines slurry from the bottom of the settler is recycled to the slurry preparation area. The de-watering system contains de-watering bins, a water tank, cooler and water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system to limit fugitive emissions. Triplicate analysis of the slag collected during a three day operational period in May while on coal and producing full power from the steam and combustion turbines, show a stable slag quality (see Table 2-11 – Slag Analysis Summary in Appendix E – Environmental Testing). During the second quarter of the year, extensive environmental testing was completed.



During GSI's operational campaigns in 1997, the gasifier operation improved over 1996 by producing over 6,213,800 MMBtu's of product syngas compared to 1996 production of over 2,767,700 MMBtu's. This represents an increase of approximately 224% over the previous year. The gasifier operated on coal for over 3,650 hours. During heatup operations, the gasifier operated on methane and a blend of coal/methane for over 1490 hours. It again must be noted that syngas generated during heatup operations is not suitable for use as fuel for the combustion turbine and that coal/methane mix is simply a transition step from methane heat-up to coal operation. Methane operations indicated in the graph indicate methane and coal/methane mix hours for heat-up of the gasifier and associated equipment and the transition onto full coal operations.

While gasifier operation was improved (as indicated by increased operational hours on coal), several important opportunities for improvement were identified and several major modifications did take place in the system to improve overall performance.

- A mechanical problem concerning cooling water flow to the gasifier water-cooled nozzles was identified in the first quarter when the piping system supplying the nozzles failed. The cause of the failure was isolated to severe vibration of the boiler feedwater makeup line to the system. During normal operation, boiler feedwater flows in a closed loop, at 450-500 psig, through the water cooled nozzles and then is cooled through heat exchange with cooling tower water. Make up water for this system is supplied by an 1800 psig system from PSI. Due to small leaks in the closed loop system, boiler feed water under 1800 pounds of pressure was entering the 500 psig system at a rate sufficient to create severe vibration in the piping system. To resolve this problem, a new source of cooling water makeup (cold condensate) was identified and utilized as a boiler feedwater replacement. The new makeup system operates at approximately 600 psig and is approximately 400 degrees F cooler than the boiler feedwater source. Vibration problems have not recurred.

- In addition to the problems associated with the cooling water loop above, failure of tubes in the cooling water loop exchanger was also identified. Previous failures of the water cooled nozzles indicated the potential that excessive cooling was taking place in the nozzles causing the syngas to cool to the point of condensation. Corrosion of the nozzles indicated that sulfur constituents and moisture from the condensing gas were causing the nozzles to prematurely fail. In an effort to prevent these failures, cooling water flow to the heat exchanger was reduced to assist in elevating the temperature of the cooling water loop. While temperatures in the cooling water loop to the water cooled nozzles increased, it was also noted that shell side cooling water had increased enough to cause shell-side boiling. This, along with the vibration problems mentioned above, eventually led to severe damage to the exchanger tubes. Corrective measures included increasing cooling water flow to the exchanger and the implementation of the new cold condensate makeup line described above. One tube failure in this exchanger did occur in the 2nd quarter as a direct result of these vibrations earlier in the year. No further tube failures occurred in this exchanger during 1997 and no further vibration has been reported.

- During a third quarter inspection of the gasifier, it was noted that there was substantial thinning of the brick refractory in certain areas. While the gasifier could have been re-bricked in the thinning areas and put back into service for the next operational run, consideration was given to the planned petcoke evaluation in the fourth quarter and deposition information that could be gained from a clean gasifier in evaluating petroleum coke deposition characteristics. It was therefore decided to swap to the spare gasifier in the third quarter. The spare gasifier has been equipped with new brick material based on the information gained from the wear in the primary gasifier to date. Dynegy personnel worked with various brick manufacturers in an effort to develop brick material that could withstand the hostile environment of the gasifier. Key criteria such as thermal growth, erosion resistance, and thermal insulating characteristics were evaluated prior to selecting a manufacturer and brick type. Again, focus for evaluation was primarily based on the above, plus extension of operational life before re-bricking is required. Evaluation of the new brick material will be accomplished on subsequent outages to determine life expectancy of the brick.

- One project identified to extend run time by reducing run-limiting deposition, was implemented in the third quarter. It involved a new process design piping arrangement placed on the transition piece between the gasifier and post-resident vessel. This new 180 degree ell transition was designed to reduce deposition and help eliminate stress between the two vessels. By design, the transition piece also created a smoother gas flow path between the two vessels for the particulate-laden raw syngas. The old design utilized a straight piece of transitional piping that connected to the gasifier second stage and the post-resident vessel just below the tops of both vessels. Gas path flow, therefore, was severely impinged creating deposition at the top of the gasifier and along the inlet wall of the post-resident vessel. Gas flow was resticted in this area causing an increase in pressure across the system and an erratic gas flow pattern. Success of the new transition piece will be evaluated on subsequent vessel inspections.

Several minor problems were identified which led to a decrease in gasifier efficiency or shut down of the operation. Those specific problems and corrective actions are identified below:

- During the first quarter of 1997, slag flow was lost due to insufficient flow of extraction gas (raw syngas utilized during normal operation to enhance slag flow) through the tap hole. Loss of extraction gas flow created a tap hole plug, which eventually led to a shut down of the gasifier. An investigation into the problem indicated that there was no mechanical process that needed evaluation or correction, but the problem existed in the computerized control code for the gasifier. The control code was changed to ensure the presence of adequate extraction gas flow and to give operations a more accurate means of monitoring flow measurement. Once the procedure was installed in the control code, no further problems with gasifier operation were noted due to extraction gas flow control.

- In the second quarter, following an inspection of the slag handling system, a significant amount of scaling was identified in the flow lines and equipment downstream of the slag crushers. Following laboratory testing, a scale inhibitor was added to the flow stream to reduce scale formation and the potential for slag flow interruption due to blockage of the lines. This application is still under evaluation.

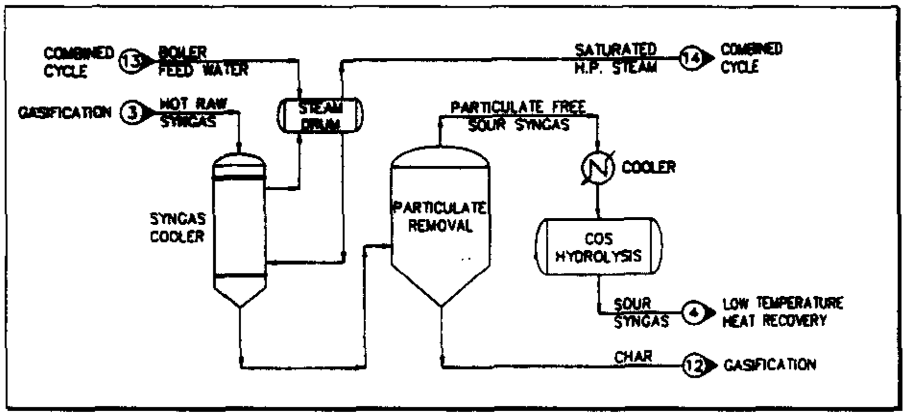
- An extraction gas analyzer failed in the third quarter due to a high velocity of particulate laden gas passing through the flow meter and associated piping. The system was temporarily corrected by increasing the piping diameter for the flow meter to reduce velocity. Following a recurrence of the problem in September, it was decided that the extraction gas analyzer would have to be totally isolated from the main gas path if the problem was going to be corrected. The analyzer inlet configuration was subsequently rearranged utilizing a side stream path with less velocity. No further problems were directly associated with this unit during the remainder of 1997.

- During the first operational run in September, it was noted that the redundant slurry flow magmeters (measuring flow to the gasifier) began deviating (from set point) significantly which reduced the stability of the slurry flow to the gasifier (which is a primary control point for gasifier operation). The deviations became so severe that it eventually resulted in a shutdown of the gasifier due to the inability of the control module to properly adjust oxygen-to-coal ratios with the deviations in flow. To correct this problem, a more aggressive preventative maintenance schedule was implemented.

- In the fourth quarter an area of the spare gasifier developed a "hot spot" on the exterior surface which required the application of cooling water to prevent further damage to the shell. When applying the cooling water spray, the water ran down one side of the gasifier creating unequal thermal growth on the opposite side. This, in turn, caused a misalignment of the slag crushers due to vessel movement, which ultimately caused a failure of the fluid coupling. The cooling water flow was drastically reduced to a "mist" which alleviated the problem of disparate thermal growth and no further failures were encountered. The hot spot was repaired internally during the next scheduled outage.

During November, a successful test burn of an alternate feedstock (petcoke) was accomplished. From November 17th to the 26th, GSI utilized approximately 18,000 tons of petroleum coke to generate syngas for PSI's consumption. Due to the higher Btu value of the petcoke, GSI was able to produce syngas with a higher Btu value at a lower slurry feed rate than that of coal. Slag production decreased due to a much lower ash content of the feedstock. Additionally, it was noted that the sulfur recovery plant operated at peak efficiencies during the trial run due to the higher sulfur content of the petcoke. Overall, the plant operated very effectively on the feedstock and proved its applicability for the generation of syngas for multiple purposes in areas where petcoke is readily available..

SYNGAS COOLING, PARTICULATE REMOVAL AND COS HYDROLYSIS

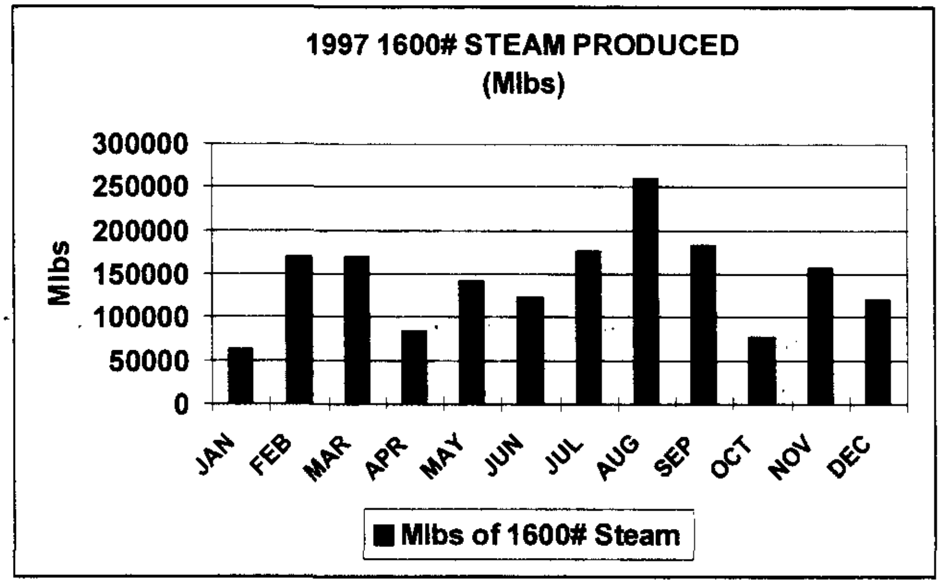


The gas and entrained particulate matter exiting the gasifier system is further cooled below 1900 degrees F in a firetube heat recovery boiler system where saturated high pressure steam is produced. This steam is then superheated in the gas turbine heat recovery steam generator for use in the steam turbine for power generation.

The raw gas leaving the high temperature heat recovery unit passes through a barrier filter unit to remove the particulates. The recovered particulates are recycled to the first stage of the gasifier. The particulate free gas is cooled further before proceeding to the carbonyl sulfide (COS) hydrolysis unit.

COS, present in the synthetic gas, is not removed as efficiently as H_2S by the Acid Gas Removal (AGR) system. Therefore, in order to obtain a high sulfur removal efficiency, the COS must first be converted to H_2S before the sour syngas enters the AGR. This conversion is accomplished in the COS Hydrolysis unit by catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide is then removed in the AGR section and the carbon dioxide remains in the product syngas utilized by the combustion turbine.

Steam production, as shown in the graph at right, reflects the operational run history of the gasifier. Total steam production for 1997 increased over 200% from 1996 as did most other operational parameters



Deposition, plugging, and corrosion within the HTHRU (High Temperature Heat Recovery Unit) continued to be of prominent concern in 1997. Several major projects and improvements occurred during the year to enhance system performance and improve reliability. Those include:

- As identified in 1996, thermal cycles of the hot syngas path were a leading contributor to HTHRU plugging due to spalling of ash deposition in upstream equipment and piping. One such thermal cycle in the first quarter led to increased plugging of the boiler tubes sufficient to require a gasifier shutdown due to high differential pressure across the boiler tube sheet. Subsequent cleanings in the second, third, and fourth quarter indicate that, while deposition may be controlled to some extent, planned outages will have to be appropriately spaced to ensure uninterrupted HTHRU operation in the future. One project, the installation of the 180 degree ell from the gasifier to the soak tank, should have an impact on boiler deposition rates by reducing the amount of deposition upstream of the boiler. This should reduce the impact thermal cycles have on the boiler inlet gas stream by reducing the potential of upstream deposition breaking loose during start up and shut down operations.

- Thermal cycles (shutdown and start-up) not only effected deposition in the system but also served to accentuate installation flaws within the piping scheme. In March of 1997, due to excessive misalignment of a piping spool during construction/installation, a syngas leak developed in a spool piece on the outlet of the waste heat boiler. The released gas combusted as it leaked from the process causing a small fire and subsequent shutdown of the gasification process. In the process of purging the system with nitrogen, the flare pilot was extinguished resulting in an odor noticeable to neighbors in the area (due to minor concentratitons of hydrogen sulfide in the purge gas). Details of this incident are further explained in the Environmental Monitoring Plan Report for 1997. This flange had a history of gas leaks, but had been previously maintained in a safe condition with appropriate bolt-torquing. After this release, the flange surfaces were welded and re-machined and the pipe reconnected with a new gasket.

Although the incidents of flange leakage were curtailed by this action, subsequent small leaks occurred within the system. Future plans include replacement of the spool and both flange pairs with hard pipe to eliminate this leak source. Proper mitering of the pipe and proper alignment should eliminate the pipe stresses in this area.

- The inlet boiler screen to the HTHRU experienced failures in the first quarter due to chemical attack from raw syngas components and excessive solids loading. Due to these failures, and previous failures that occurred in 1996, a new material of construction was selected for installation in the second quarter of the year. Following the installation of the new screen early in the second quarter, the screen remained in place for the remainder of the year experiencing only normal wear while limiting deposition on the boiler inlet. Although the new screen may have successfully extended the life of a given run cycle, engineering is still investigating new screen material, which will outperform the current design.

Several other opportunities for improvement occurred during the year which, while having an impact on operation run characteristics and availability, did not involve major project development. The following is a brief summary of those opportunities:

- Removal methods for boiler tube deposition continue to be critical factors in reducing the amount of time required for a plant turnaround. Due to the tenacity and hardness of the deposition on the tube walls, special cleaning methods are being developed to reduce off-line cleaning time. While some success in reducing cleaning time was made during 1997, efforts to further improve methods and mechanical cleaning procedures will continue in 1998.

- Instrumentation problems in the first quarter caused two shutdowns of the gasifier when boiler feedwater pressure transmitters froze creating a false flow signal and subsequent low steam drum level. Insulation and freeze protection for the transmitters has been upgraded to prevent recurrence. Additionally, control logic for the boiler steam drum was upgraded during the second quarter. This upgrade makes the level control less sensitive to the vagaries of flow measurements.

- During 1997, the gasification process experienced shortened run cycles due to the loss of boiler feed water from PSI on six different occasions. Two of the initial trips during the first quarter were identified as being associated with difficulties experienced in the Uninterruptable Power Supply (UPS) system. Three of the boiler feedwater losses have never been traced to a specific cause, though the UPS is suspected.

Although the dry char filtering system continued to demonstrate improved performance throughout 1997, the system is still undergoing development both in the operational area and in the area of design and metallurgy.

- During the first quarter, and after installation of first generation metal filter candles in the fourth quarter of 1996, a single gasifier trip in January was caused by primary filter failure. The failure was due to a combination of corrosion-weakened metal filters and flow surges through the vessels caused by backpulse valve failures. The failure of the backpulse valves served to hasten filter degradation due to the inability to send backpulse gas through the filters to remove the collected char. During that time, flow imbalances caused a significantly increased flow of gas through the clean filters, damaging the already weakened filter elements. Some of the experimental metallurgy's utilized for filter construction during this run showed evidence of corrosion after only 523 hours of service and one type was corroded to the extent that the filters lost strength and ductility. During the ensuing plant outage, all of the filters of this type were replaced with filters of alternate metallurgy's that demonstrated superior resistance to corrosion. All of the pulse valves were disassembled and many were found to have extensive seat damage. The valves were rebuilt utilizing the existing seat design and the pulse gas heat exchanger was taken out of service for the next run. Leakage of the valve seats effectively stopped after this correction. Preliminary indications are that thermal stresses caused by the hotter pulse gas may have resulted in sufficient distortion of the valve bodies to cause the disks to be improperly aligned with the seats.

- Overall, the dry char system continued to operate acceptably until additional problems occurred in the fourth quarter, when the dry char system caused the plant to be brought off line four times. Three of the four occurrences were caused by a flow imbalance between the two vessels and poor char recycle ejector performance resulting in high vessel levels and resultant plant trips. A dimensional discrepancy in one of the recently fabricated ejector internal parts was determined to be the cause of this failure. After replacing these parts, plant trips due to ejector performance problems were eliminated for the remainder of 1997.

- High primary filter blinding rates continued in the fourth quarter and, as a result, the filters were cleaned during an extended plant outage in October. The high blinding rate was partially due to a high temperature heat recovery steam boiler tube leak. Filter blinding rates were again high during the operating period preceding the petcoke test. Upon completing this test, the filters were again cleaned in early December. A new cleaning procedure resulted in a significantly higher recovery of filter permeability. As a result, the primary vessel differential pressures in December were much lower compared to the October startup.

Other enhancements to the system, including a modification to the internal inlet gas distribution system in the dry char vessels, installation of test panels, and installation of a new test unit, continued to provide system enhancements which led to longer operational time frames. Specifically, those items were:

- A design change was made to provide more uniform flow distribution throughout the vessel, thereby reducing both the gas velocity in the high-wear areas of the inlet distributor piping and the particle impingement velocity on the filters.

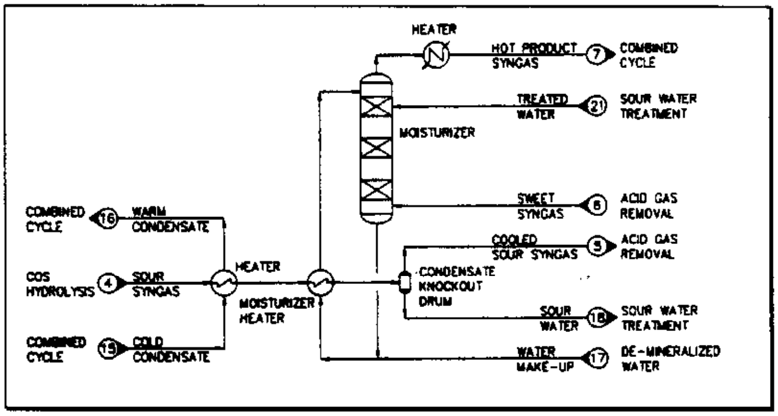
- Several panels of abrasion resistant materials were installed in the primary distributor system. These panels are being tested for possible future application in the system to improve distributor part life.

- Initial construction began on a new Dry Char Slip Stream unit which will provide us the opportunity to test filter candles and materials of construction outside of the primary filtration vessels. (This slip stream unit project is being built under a separate cooperative agreement.) The project was completed and put into service during the fourth quarter of 1997. No results were recorded during the calendar year due to the short run time from commissioning to the end of the year.

- During a second quarter run campaign, it was discovered that tar condensation on the filters was a major contributor to filter flow resistance. The filters were cleaned and returned to service. During the subsequent campaign, the reactor outlet was operated at a higher temperature to enhance tar destruction and improve filter run time. This procedure proved effective in the reduction of tar and thus improved overall run time on the dry char filtration system.

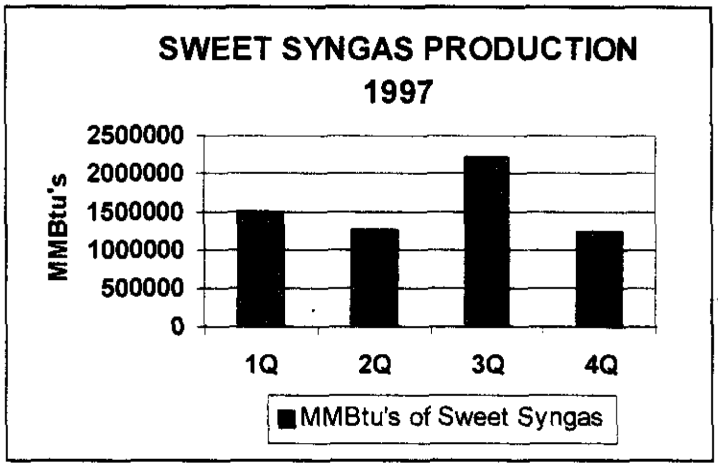
The Carbonyl Sulfide (COS) catalyst system ran well within limits during the entire year for 1997. Although conversion efficiencies were somewhat reduced by a temperature excursion and subsequent catalyst deactivation in the fourth quarter of 1996, operations have compensated for the loss by operating the reactor at a slightly higher gasifier temperature to reduce sulfur levels in the product gas. The carbonyl sulfide catalyst was replaced in the fourth quarter of 1997 and the system continued to operate well within design limits for the remainder of the year.

LOW TEMPERATURE HEAT RECOVERY AND SYNGAS MOISTURIZATION



After exiting the COS hydrolysis unit, the remaining low level heat is removed from the syngas in a series of shell-and-tube exchangers located before the Acid Gas Recovery (AGR) system. This cooling condenses water, ammonia, carbon dioxide, and some hydrogen sulfide (H_2S) producing sour water, which is collected and sent to the sour water treatment unit. The heat removed prior to the AGR system provides moisturizing heat for the product syngas, steam for the AGR H_2S stripper, and condensate heat.

Cooling water provides trim cooling to ensure the syngas enters the AGR at a sufficiently low temperature (approximately 100 degrees F). The cooled "sour" syngas is fed to an absorber in the AGR system where the solvent selectively removes the H_2S to produce a "sweet" syngas (low in H_2S). The "sweet" syngas is then moisturized to a water content of approximately 20% by volume using low level heat from raw syngas cooling. Moisturization is accomplished by contacting the "sweet" syngas and hot water counter currently in a high surface area contacting column. After the moisturizer, the syngas is preheated before being directed to the combustion turbine. Moisturization and preheating of the syngas increases efficiency in the combustion turbine and reduces the steam requirement for NO_x control.



Total sweet syngas (product syngas) production for 1997 totaled approximately 6, 206,900 MMBtu's with the highest production occurring in the third quarter. Sweet syngas moisturization operated efficiently and provided a consistent product gas moisture content of approximately 20% throughout 1997. Product syngas quality remained high and will be discussed later in this section.

Problems in this area centered around the new Chloride Scrubbing system which was installed in the third quarter of 1996. While the system continued to show good scrubbing efficiency throughout the year, the demister packing in the top of the vessel continued to create problems in the system due to coal tar plugging. While no problems were encountered in the first quarter of the year, the second quarter saw increasing problems with tar deposition. During the second quarter the system exhibited an increasing differential pressure across its packing. The pressure drop escalated to the point that liquid was entrained from the scubber and carried into the gas path. For a short duration, this liquid overwhelmed the demisters and knockout drums sending water into the downstream COS hydrolysis reactors. The automatic control system diverts flow away from the reactors when water entrainment is detected but some water potentially reached the catalyst beds during the transitions. The root cause of the incident was determined to be tar deposits on the packing which impeded gas and liquid flow through the column. Tar prevention was achieved by operating the 2nd stage gasifier outlet at a higher temperature to maximize tar destruction. The column packing was cleaned and put back into service in preparation for the third quarter run. Towards the end of the third quarter the column again began exhibiting a high differential pressure. The problem, again, was identified as tar formation.

To correct the problem manual flushes were periodically implemented, during reduced rate operations, to mitigate the high differential pressure and avoid liquid entrainment into the gas path. Additionally, the time spent operating at low rates will be limited in future operational campaigns. This process was instituted due to the fact that, despite appropriate designated temperature control in the gasifier outlet, heat loss from the system is too great during low flow operations to maintain these temperatures throughout the system. Despite the flow problems, the chloride removal system was virtually unaffected. Fourth quarter operation, though showing some increase in differential pressure across the column, continued without incident. A complete vessel inspection is planned for the first quarter of 1998 to assess corrective action and to determine if tar buildup in the packing material is still occurring.

The syngas flare system is considered part of the overall low temperature heat recovery and moisturization process due to the fact that product syngas and off spec gas is flared during normal operation, system startup and system shutdown. During a syngas leak and subsequent flange fire event in the first quarter (previously mentioned) the flare system malfunctioned by losing flame and causing a release of purge gas containing hydrogen sulfide. The malfunction was attributable to a marginally combustible stream created during the system nitrogen purge process passing to the flare. During this event, methane (normally used to augment syngas during the purge process) flow to the flare tip was not sufficient to ensure that a combustible gas existed at the three flare pilots. The pilots were snuffed out in the process and the gas exited the flare unburned. To correct the problem, three new "windproof" pilots were installed on the flare tip during the second quarter outage. The control code for the purge process was also upgraded to ensure that a sufficient volume of methane gas is added to the flare gas to ensure combustion during system purge.

One of the additional problems that existed at the flare is the fact that, during startup operations and in the event of a combustion turbine trip, gas passing to the flare creates an noticeable noise level to the surrounding community. Noise levels in excess of 60-65 dB (average) were recorded at the nearest residence during one such event. To rectify this problem, a new flare tip was installed during the third quarter outage to reduce the overall noise level. The old three foot diameter tip was replaced with a five foot diameter tip. Preliminary noise monitoring data indicates a significant reduction of noise in the plant and surrounding community during high rate flaring operation (to as low as 55-60 dB). To further reduce noise levels and the time required to flare at high rates during start-up operations, the procedure for transfer to coal operations was modified during the fourth quarter to make the swap to the combustion turbine at a lower coal feed rate. This reduced fuel consumption and reduced the flare noise level as well.

Product syngas quality remained relatively consistent throughout 1997. One of the primary reasons for such consistency was the use of a single coal source for the year. Minor variations in hydrogen sulfide and carbonyl sulfide concentrations (in ppm) were primarily due to equipment problems in the COS catalysis reactor and acid gas recovery systems. Variations in Btu value, hydrogen concentration, carbon monoxide and carbon dioxide concentrations, and methane content were directly related to operational characteristics of the system (and more specifically to variations in the oxygen to coal ratios of the gasifier feed) and cannot be attributed to variations in coal feedstock. Some assumptions can be made for variations in syngas makeup due to the petroleum coke trial in the month of November.

Hydrogen Content: Hydrogen content (percent) in the syngas varied from an average monthly low of 32.9% in January to a high of 34.4% in April.

Carbon Dioxide Concentration: Carbon dioxide (percent) in the syngas varied from an average monthly low of 16.6% in December to a high to 16.9 in April.

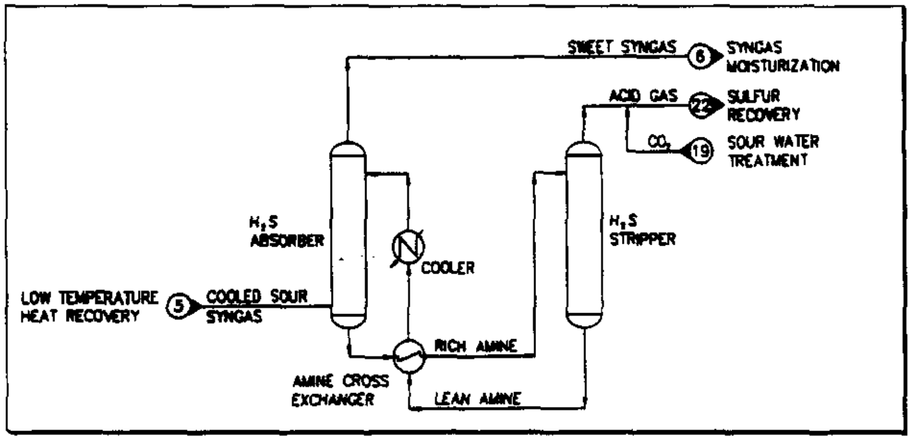
Carbon Monoxide Concentration: Carbon monoxide (percent) in the syngas varied from an average monthly low of 42.2 in January to a high of 46.7 in November. There appears to be no statistical basis for considering petcoke as a contributor to the high value even though it occurred in November. December concentrations were very similar while operating on coal.

Methane Content: Methane (percent) in syngas showed very little variability throughout the year. The month of November recorded the only significant deviation from the norm with a low of 1.04%. The remaining eleven months recorded averages of, at or just slightly less than, 2%. Methane concentrations in the syngas were significantly lower during petroleum coke operations. Average concentrations during the petcoke trial were approximately 0.5% as methane in the syngas. This is primarily due to the fact that the gasifier was operated approximately 200 degrees hotter during petcoke operation and product gas methane concentration drops as gasification temperatures increase.

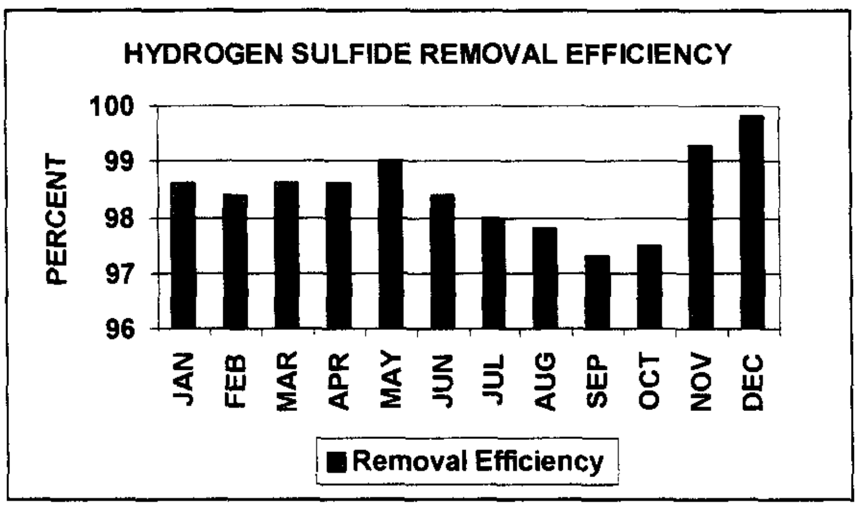
Hydrogen Sulfide Concentration: H_2S concentration (parts per million, ppm) in the product syngas showed some variability due to previously mentioned COS catalyst deactivation and downstream problems associated with the MDEA absorber column. Just prior to COS catalyst replacement, H_2S values climbed to a monthly average high in September of 106.5 ppm. After replacing the catalyst, the H_2S concentration dropped back down to normal levels as indicated by a November average of 43.08 ppm. The lowest average monthly ppm value occurred in May with an average concentration of 29.21 ppm.

Carbonyl Sulfide Concentration: COS concentration (ppm) in the product syngas shows an expected variability due to the equipment problems indicated above. While the first five months of the year show a consistent concentration of approximately 40-60 ppm, the months of July, August, September, and October show significant increases in the monthly average to as high as 110 ppm (September and October). After the COS catalyst was replaced, average monthly concentrations dropped to approximately 21-22 ppm (November and December).

ACID GAS REMOVAL



The first step in the sulfur removal process is the Acid Gas Removal (AGR) system, which removes the hydrogen sulfide present in the "sour" syngas. The AGR system also produces a concentrated H_2S stream (acid gas) that is fed to the Sulfur Recovery Unit (SRU). The AGR system is a totally contained system and does not release emissions to the atmosphere. Hydrogen sulfide is removed via the absorber using a H_2S solvent, methyldiethanolamine (MDEA). The hydrogen sulfide rich solvent exits the absorber and flows to a re-boiled stripper where the hydrogen sulfide is steam stripped at low pressure. The concentrated H_2S stream exits the top of the stripper and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper and is cooled, then recycled to the absorber.



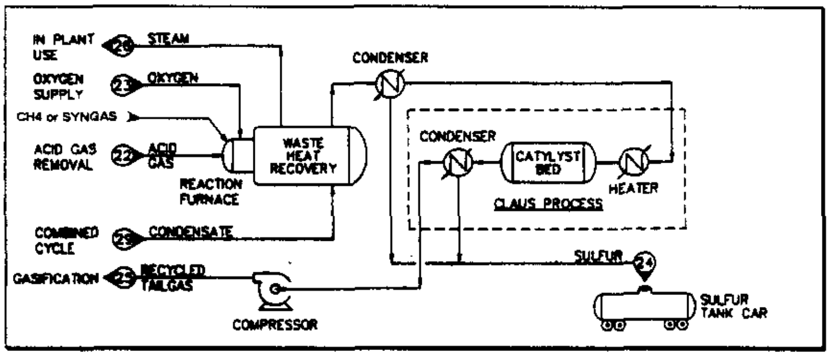
Acid gas removal efficiencies remained fairly consistent throughout 1997 as can be seen by the chart at right. The efficiency calculation uses total combustion turbine stack and flare stack syngas emissions (as sulfur) compared to the total sulfur feed in the gasification plant (sulfur, dry-weight percent) for the most conservative estimate of performance. As was discussed earlier in this report, first, second, and third quarter efficiencies were slightly lower, when compared to the fourth quarter, due to a decrease in activity in the COS reactor catalyst beds and in their ability to convert carbonyl sulfide to hydrogen sulfide.

In early January the amine absorber internals sustained damage resulting from excess loading of the trays which directly effect MDEA contact with the hydrogen sulfide enriched sour gas. Column performance was compensated for during the quarter by operating the column on a higher level amine feed point which increases contact area with the amine. The tray damage to the column was repaired during the late April outage and column performance and feedpoint returned to normal. However, overall first quarter efficiencies were somewhat higher due to an extended operating period (which allowed for system optimization) and cooler ambient temperatures, which directly affect and increase solvent efficiency.

Reduced efficiencies encountered in the third quarter can be directly attributed to the increase in solvent temperature occurring in the summer months and continued degradation of the COS catalyst. The loss of catalytic reaction creates a condition where carbonyl sulfide concentrations at the absorber column inlet exceed design criteria and the COS is hydrolyzed and absorbed by the amine which increases the hydrogen sulfide content in the outlet gas and less free absorption sites remain in the amine. A single event also occurred in the third quarter directly effecting absorber efficiency when column performance was compromised when differential pressure exceeded design limits and one of the gas-liquid contact trays collapsed. Solvent anti-foaming compound was exhausted, and went unnoticed, ten days prior to this event and consequental solution foaming was identified as the root cause of the tray failure. This event eventually led to a pemitted sulfur dioxide air permit exceedance at the flare when product syngas had to be flared because the sulfur limit in the product syngas was no longer acceptable for delivery to PSI. Details of the environmental significance of this event are outlined in the Environmental Monitoring Annual Report for 1997.

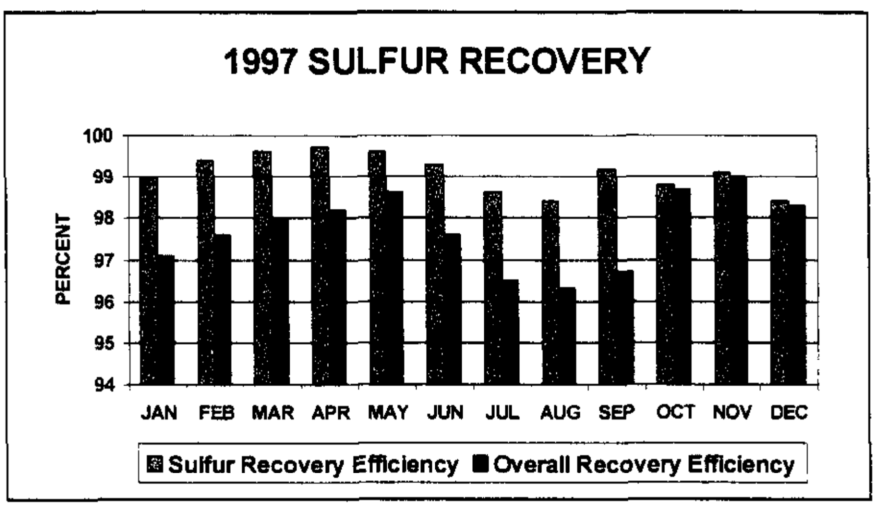
In the fourth quarter, because of an ever-increasing heat stable salts loading of the amine, a vacuum distillation was performed on the entire absorbent inventory to remove the salts. The distillation recovered 82% of the solvent while removing the heat stable salts. Efficiency increases can be attributed to the fresh solvent application. Additionally, during the fourth quarter, the COS reactor catalyst was replaced which also aided in an increased efficiency to above 99%. Projects have been proposed for 1998 to investigate the rate of heat stable salt formation and configuration of the ISEP unit to better handle on-line removal of the salts. Information on these projects will be discussed in the 1998 annual report. It should also be noted that the AGR system operated more efficiently due, in part, to the higher sulfur loading created by the introduction of petroleum coke in November. Concentrations of sulfur, greater than 5% (dry-weight) were encountered in the petroleum coke and were well within the design limits of the AGR and Sulfur Recovery Unit.

SULFUR RECOVERY



The concentrated hydrogen sulfide stream from the AGR system and the CO_2 and H_2S stripped from the sour process water are fed to a series of catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur is recovered as a molten liquid and sold as a by-product. A tailgas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of hydrogen sulfide, exits the last catalytic stage.

The tail gas from the SRU is hydrogenated to convert all the sulfur species to H_2S, cooled, compressed and then directed to the gasifier. This allows for a very high sulfur removal efficiency with minimal recycle requirements. Provisions in the system also allow for final treatment of the tail gas in the tail gas incinerator. A tank vent stream is also treated in the incinerator. The tank vent stream is composed of air purged through various in-process storage tanks and contains very small amounts of acid gases. The high temperature incinerator efficiently destroys H_2S remaining in the stream by converting it to SO_2 before the exhaust gas is vented to the atmosphere from a permitted air emissions source .



Total plant sulfur removal efficiencies indicated at left are split into two specific areas. The blue columns indicate the efficiency of the SRU. Overall recovery efficiencies (red columns) compare total joint venture emissions (as sulfur) verses total sulfur feed to the gasifier, and recovered sulfur. Overall, this graph compares quite favorably with the reduction in reactivity of the COS catalyst and illustrates a clear degradation over the course of 1997. Fourth quarter replacement of the catalyst shows a significant increase in the overall joint venture removal efficiency. A total of 8,568 tons of sulfur were recovered during 1997. A recovery breakdown, by quarter, is indicated below:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
1,961	1,660	2,890	2,057

Significant reductions in efficiency of sulfur removal were noted in the third quarter due to decreasing acid gas concentration in the feed to the SRU. Average ambient temperature increased for the quarter, decreasing selectivity in the acid gas removal solvent. The result is increased acid gas flow and lower H_2S feed concentration to the SRU, hindering efficiency.

Increasing efficiency in the fourth quarter can be attributed to (especially in November) the petroleum coke test. During this period, the hydrogen sulfide concentration increased which improved the efficiency of the Claus units.

During the year several incidents in the SRU led to either production turndowns, or complete shutdowns of the gasification process.

- In the first quarter several minor problems associated with a plugged condenser and a plugged tank vent on the sulfur storage unit caused several hours of reduced production. Both of these problems were quickly resolved and full production rates were restored without further incident. Corrective measures were placed in the operating procedure and maintenance guide and no further problems of this nature occurred during the year.

- In the third quarter the SRU reaction furnace tripped four times. In each case, the operating rates were only reduced for a few minutes until the unit could be re-started. Corrective actions to including hardware, software and additional operator training were implemented to minimize furnace upsets. No further incidents of this nature were recorded for the remainder of the year.

- On November 12th, the pressure safety valve protecting the acid gas stripping column failed, relieving at a pressure less than setpoint. Acid gas from the column was relieved into the flare header, resulting in an exceedance of sulfur dioxide permitted limits at the flare. Investigation into the mechanism of failure revealed that debris in the pilot valve prevented proper seating. This allowed the main valve to remain open at pressures below relief setpoint. The pressure safety valve was subsequently removed and an alternate overpressure protection device has been employed. The permit exceedance discussed herein, was appropriately reported and is documented in the annual 1997 Environmental Monitoring Plan Report.

Several projects were implemented in 1997 in the SRU to improve overall reliability and maintainability. Those projects were:

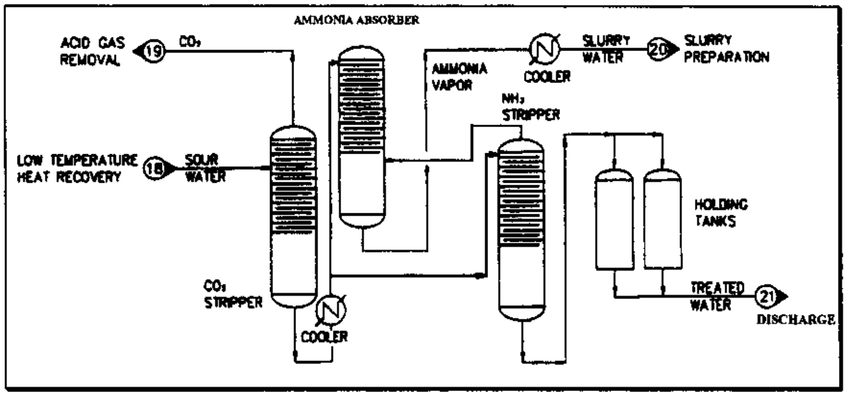
- In the first quarter the relocation of a particular temperature measurement device in the SRU reactor furnace was accomplish which was significantly improved system reliability and eliminated repetitive maintenance costs associated with the system.

- The steam generator for the tail gas incinerator was improved to lower incidences of leaks in the intermediate steam drum pressure safety valves. Rupture discs now isolate the safety selector valve from the safety valves themselves which has significantly reduced maintenance costs associated with repair of the valves.

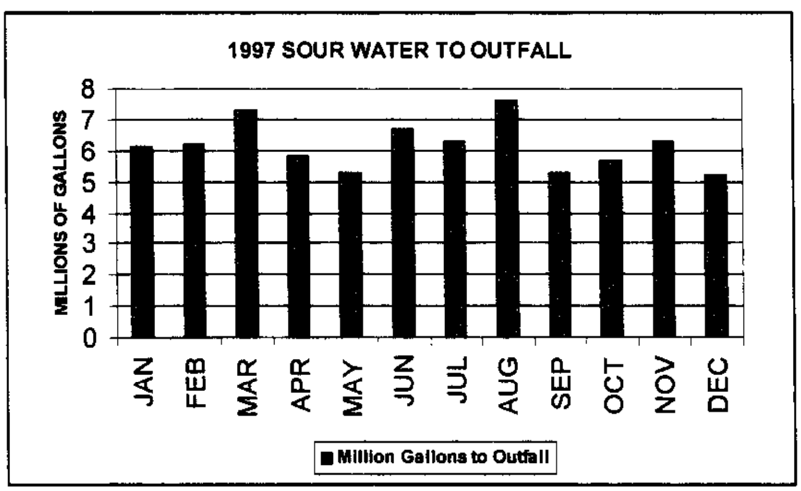
- In the second quarter, a single project designed to enhance safety, reduce emissions, increase availability and lower O & M costs was instituted. A sulfur "seal leg" was installed at the hydrogenation pre-heater along with an ancillary heating system. The project was designed to ensure liquid flow at the look box and prevent overpressure by not allowing a solid plug of sulfur to form in that area. Personnel exposure and disposal costs have been reduced as a direct result of this project.

- During the third quarter a sliding base was installed on the existing sulfur pump system to reduce piping stress and recurring pump base stress failures. Installation of this base should significantly lower maintenance costs associated with pump and piping repair in this area.

SOUR WATER TREATMENT



Water condensed during cooling of the sour syngas contains small amounts of dissolved gases, i.e. carbon dioxide (CO_2), ammonia (NH_3), hydrogen sulfide (H_2S), and trace contaminants. The gases are stripped out of the sour water in a two step process. First, the CO_2 and the bulk of the H_2S is removed by steam stripping in the CO_2 stripper column. The stripped CO_2 and H_2S are directed to the SRU. The water exits the bottom of the column, is cooled, and a major portion is recycled to slurry preparation. Any excess water is treated in the ammonia stripper column to remove the ammonia and remaining trace components. The treated water can be directed to the moisturizer or discharged from the plant. If out of specification for discharge, the treated water can be stored in holding tanks for further testing to determine final disposition. Discharge of this water stream is controlled or regulated as a combined stream with PSI's plant discharge into water outfall pond 102.



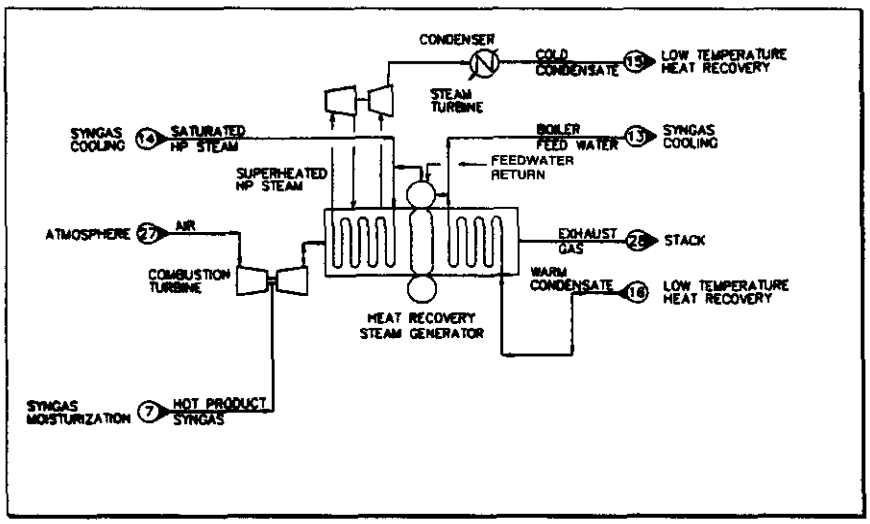
As shown in the bar chart at right, sour water to the outfall remained fairly consistent in volume through 1997. Quarterly flows totaled 19.6 million gallons in the first quarter; 17.8 million gallons in the second; 19.2 million gallons in the third and; 17.2 million gallon in the fourth quarter. In the second quarter auxiliary heat exchange capacity was increased for the ammonia quench column. As a result, ammonia emissions from the sour water make-up to the rod mill have been eliminated. Also, ammonia salt deposition in the tail gas recycle compressors has been eliminated, greatly reducing operating and maintenance costs on the compressors.

In the third quarter, a sour water carbon filter vent containment system was installed to prevent fugitive odors to personnel. This project enhances both safety and environmental stewardship by eliminating another source of fugitive emissions. Fourth quarter enhancements to the system included the conversion of an existing activated carbon storage tank to serve as a caustic tank.

Caustic has been added to the ammonia stripping column to further reduce the concentration of ammonia to the permitted outfall. Until this project, the caustic source was the caustic feed to the Ion Separation (ISEP) unit. Recognizing that a lower, less expensive grade of caustic could be used, a drum has been retrofitted to serve as the supply for the ammonia stripping column. This project should serve to significantly lower operating costs for the sour water unit.

Specific information about the quality of the water to the outfall is covered under the 1997 Environmental Monitoring Plan Annual Report and can be used as an additional reference to provide more specific information about discharge quality.

COMBINED CYCLE POWER GENERATION



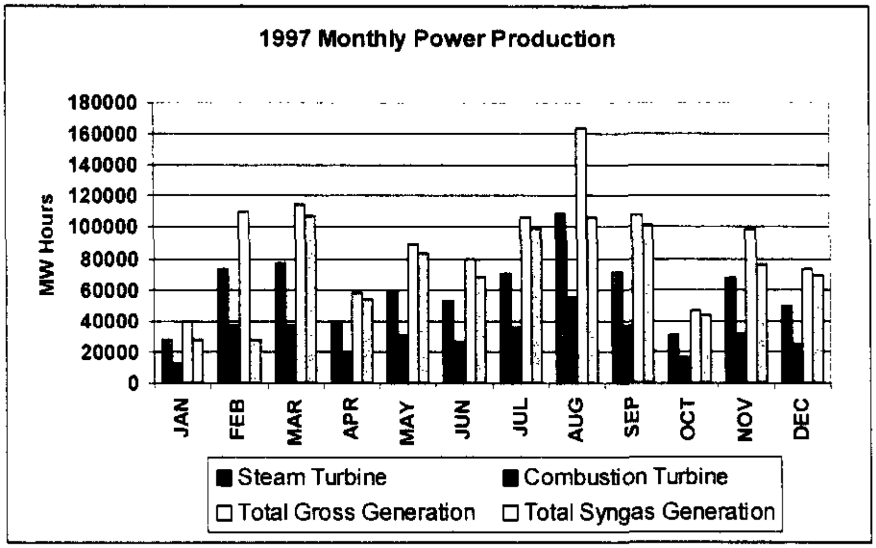
The combined cycle system consists of a combustion turbine generator, heat recovery steam generator (HRSG), reheat steam turbine generator, condenser, deaerator, flash drums, condensate pumps and boiler feedwater pumps.

The gas turbine (GT) is a nominal 192 MW advanced cycle combustion turbine fueled primarily by syngas. The General Electric 7FA combustion turbine was the largest in North America when installed in 1995. Fuel moisturization and steam injection control NOx emissions and increase MW output. Combustion air is drawn through inlet filters from outside the building housing the gas turbine. Combustion exhaust gases are routed to the HRSG. No. 2 fuel oil is used as back-up fuel for the gas turbine during startup and shutdown, and other periods when syngas is unavailable. Fuel oil is stored in tanks located within the existing plant.

The HRSG recovers heat from the GT exhaust gases to generate high pressure steam. This steam, combined with the steam from the syngas cooler, repowers the Unit 1 reconfigured steam turbine. Steam generated in the HRSG is piped to and from the steam turbine via extensive piping additions. The HRSG receives GT exhaust gases and generates steam at 1600 deg F and 1000 psig (main steam) and reheats extraction steam from the steam turbine to 1000 deg F at about 750 psig extraction pressure (reheat steam). The HRSG is specifically designed for high operating efficiency and configured for horizontal flow through a series of vertical heat transfer modules. Design of the HRSG is optimized for a syngas fired gas turbine.

The Wabash River Station Unit 1 steam turbine is located in the existing powerhouse. The steam turbine was originally supplied by Westinghouse and went into commercial operation in 1953 at a nominal rating of 99 MW.

The steam turbine was designed for reheat operation with five levels of extraction steam used for feedwater heating. To maximize efficiency, feedwater is now heated in both the HRSG and the gasification plant. With the need for extraction steam *from* the steam turbine eliminated, the steam previously extracted now passes *through* the steam turbine to generate 105 MW of power. As a result, minor modifications to the turbine steam path ensure acceptable steam path velocities. The generator and main power transformer continue to be used and have required only minimal modification.



As can been seen by the chart at left, the third quarter produced the largest total power output for the year. In the month of August figures for total gross generation (yellow) exceeded 160,000 megawatts for the first time since project start up. The months of March, May, July, August, September, November and December show generation in excess of 60,000 megawatts on the combustion turbine with syngas. Electricity production for the year realized an increase of over 200% over 1996 and continues to show improved consistency of operation. The following table illustrates production during 1997:

	1 QTR	2QTR	3QTR	4QTR	TOTAL
Combined Cycle Operating Hours On Syngas	**870**	**730**	**1,329**	**766**	**3,695**
Longest Continuous Run Hours On Syngas	**330**	**185**	**360**	**230**	
Maximum CT Output (MW)	**192**	**192**	**192**	**192**	
Maximum ST Output (MW)	**96**	**100**	**100**	**100**	
Total Gross Generation (MWHours)	**240,000**	**205,000**	**307,274**	**189,410**	**941,684**

Budget Period 3 Activities

Budget Period 3 began on November 18, 1995. The costs shown reflect operational expenditures along with major process improvements implemented in 1997. Operations and systems data collected during the year will assist in the demonstration and commercialization of the technology.

	Revised Baseline Budget (per Cont. App. for Budget Period 3)	Actual Budget Period 3 Cumulative Spending as of 12/31/97
Participant Share	$52,300,566	$49,012,822
DOE Share	$52,300,566	$34,829,682
Total	$104,601,132	$83,842,504

DOE Reporting and Deliverables

Spending and budget reports were submitted on both a monthly and quarterly basis according to the requirements of the Cooperative Agreement. Project reviews and Joint Venture quarterly reports were provided to the DOE. The following reporting requirements were submitted in accordance with Attachment C, sections 6 and 7 of the Cooperative Agreememt:

- Project Management Plan
- Environmental Monitoring Reports
- Operations Summary Reports

Other Activities

Several public relations and education activities were carried out in 1997. Appendix C (Tab C) provides a list of selected public information and trade and technical papers presented by Destec or PSI personnel related to the WRCGRP.

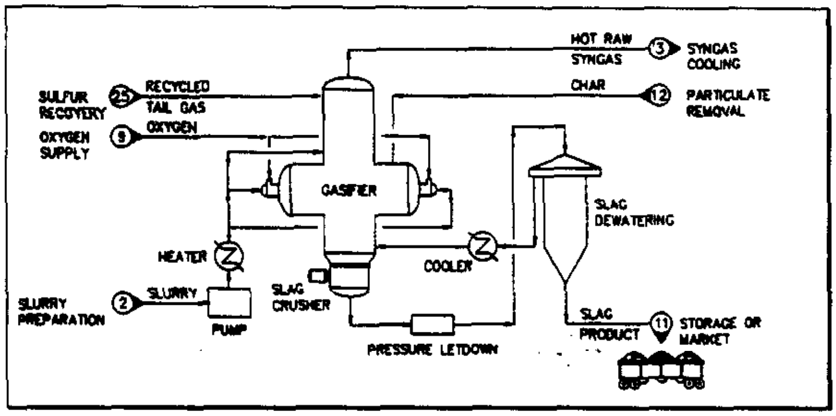
1998 ACTIVITIES AND MILESTONES

Activities in 1998 will focus primarily on continued evaluation of new project installations and renewed focus on proper gasifier operations. Major activities for 1998 will include the following:

- Evaluation of the Dry Char system element metallurgy.
- Evaluate gasifier temperature control to aid in prevention of ash deposition.
- Achieve an increasingly effective understanding of the systems and subsystem operating characteristics.
- Maintain/improve the expected dispatch orders in the Cinergy system.
- Fulfill the provisions of the Environmental Monitoring Plan.
- Obtain the data base and experience-base necessary to advance and meet the commercial markets for the technology.

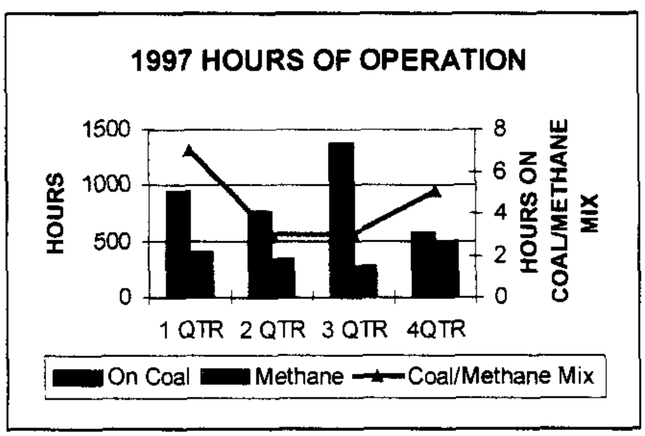
Other Activities

Other activities of significance include meeting the DOE review and reporting requirements and further development of effective operations and maintenance programs. During 1998 community relations and education programs will be continued.



Slag flows continuously through the tap hole of the first stage into the water quench bath, located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This process of continuous slag removal is compact; minimizes overall height of the gasifier structure; eliminates the high-maintenance requirements of problem prone lock hoppers; and completely prevents the escape of raw gasification products to the atmosphere during slag removal.

The slag slurry leaving the pressure let down system flows into a de-watering bin. The bulk of the slag will settle out in this bin, while the water overflows a weir at the top of the bin to a settler in which the slag fines are settled and removed. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. De-watered slag is loaded into a truck or rail car for transport to market or its storage/disposal site located on the south end of the Wabash River Generating station. The fines slurry from the bottom of the settler is recycled to the slurry preparation area. The de-watering system contains de-watering bins, a water tank, cooler and water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system to limit fugitive emissions. Triplicate analysis of the slag collected during a three day operational period in May while on coal and producing full power from the steam and combustion turbines, show a stable slag quality (see Table 2-11 – Slag Analysis Summary in Appendix E – Environmental Testing). During the second quarter of the year, extensive environmental testing was completed.



During GSI's operational campaigns in 1997, the gasifier operation improved over 1996 by producing over 6,213,800 MMBtu's of product syngas compared to 1996 production of over 2,767,700 MMBtu's. This represents an increase of approximately 224% over the previous year. The gasifier operated on coal for over 3,650 hours. During heatup operations, the gasifier operated on methane and a blend of coal/methane for over 1490 hours. It again must be noted that syngas generated during heatup operations is not suitable for use as fuel for the combustion turbine and that coal/methane mix is simply a transition step from methane heat-up to coal operation. Methane operations indicated in the graph indicate methane and coal/methane mix hours for heat-up of the gasifier and associated equipment and the transition onto full coal operations.

Appendix A
Glossary of Acronyms

CAAA	-	Clean Air Act Admendments
CCT	-	Clean Coal Technology
CGCC	-	Coal Gasification Combined Cycle
COS	-	Carbonyl Sulfide
DOE	-	Department of Energy
EPA	-	Environmental Protection Agency
HHV	-	Higher Heating Value
HRSG	-	Heat Recovery Steam Generator
IDEM	-	Indiana Department of Environmental Management
ISEP	-	Ion Separation unit
LGTI	-	Louisiana Gasification Technology, Inc.
NEPA	-	National Environmental Policy Act
NPDES	-	National Pollutant Discharge Elimination System
P&ID	-	Piping and Instrument Drawings
PMP	-	Project Management Plan
PON	-	Program Opportunity Notice
WRCGRP	-	Wabash River Coal Gasification Repowering Project

Appendix B
List of Figures

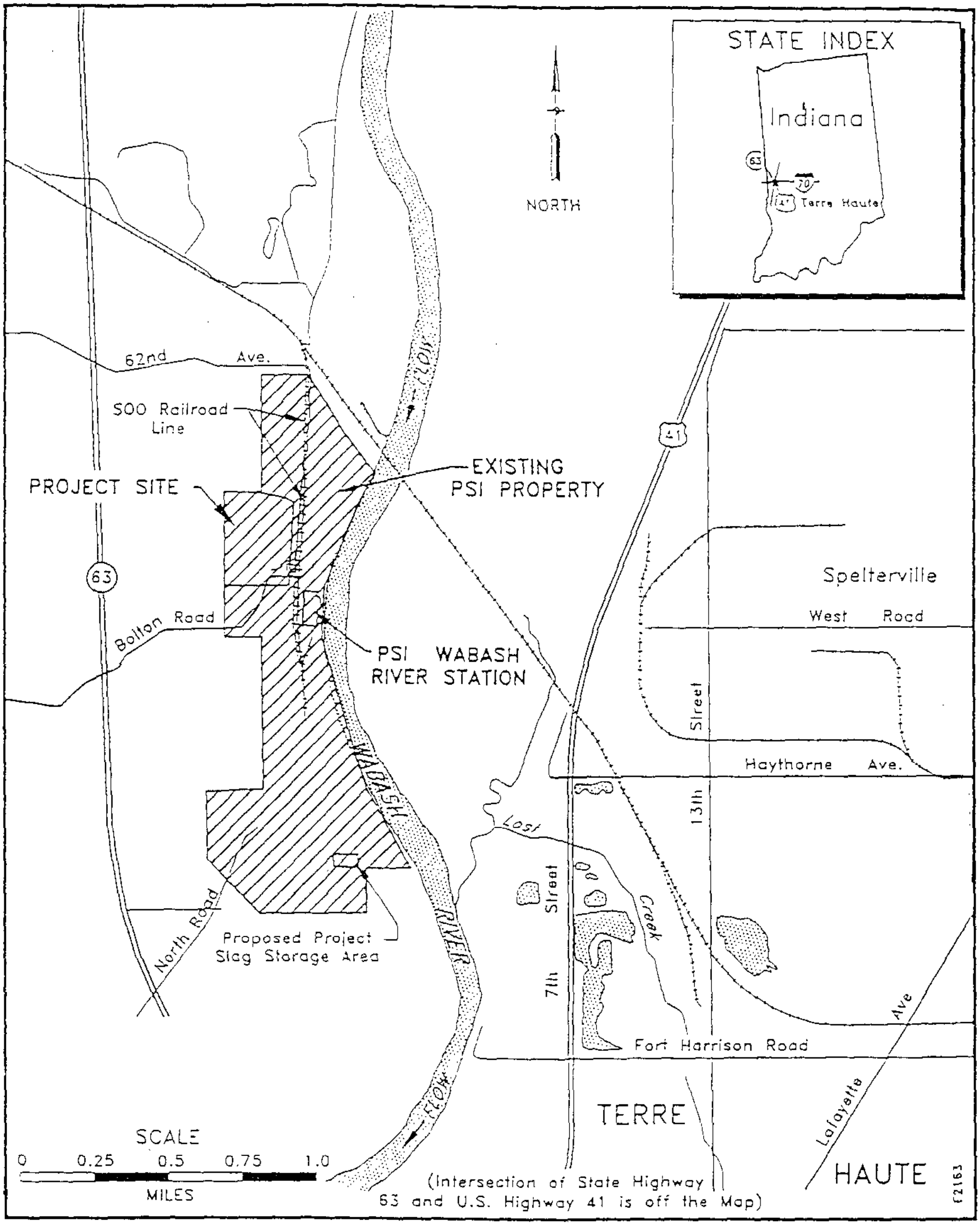


Figure 1 General Location Map Showing the Site of the Project

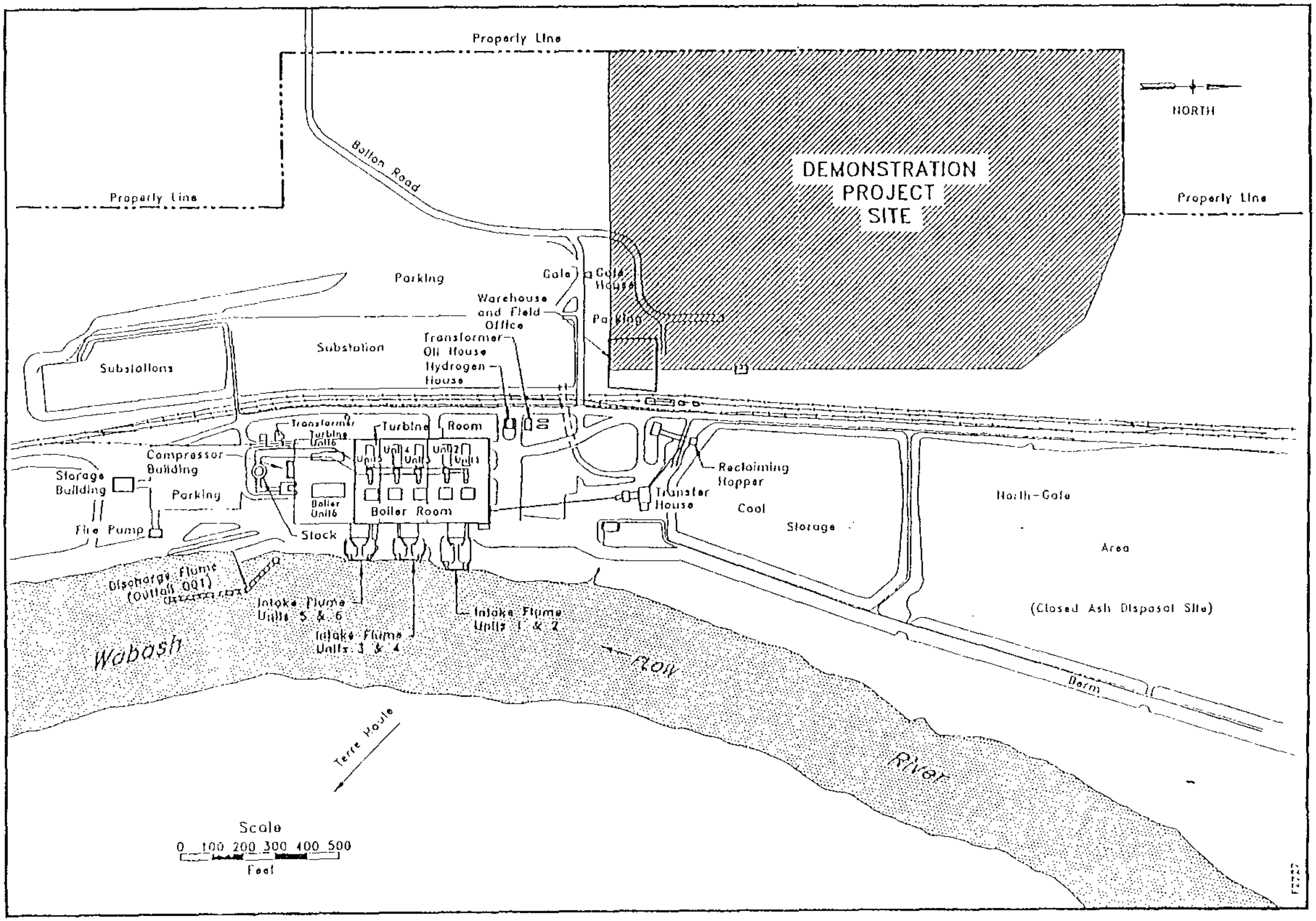


Figure 2 Site Map of the Wabash River Generating Station

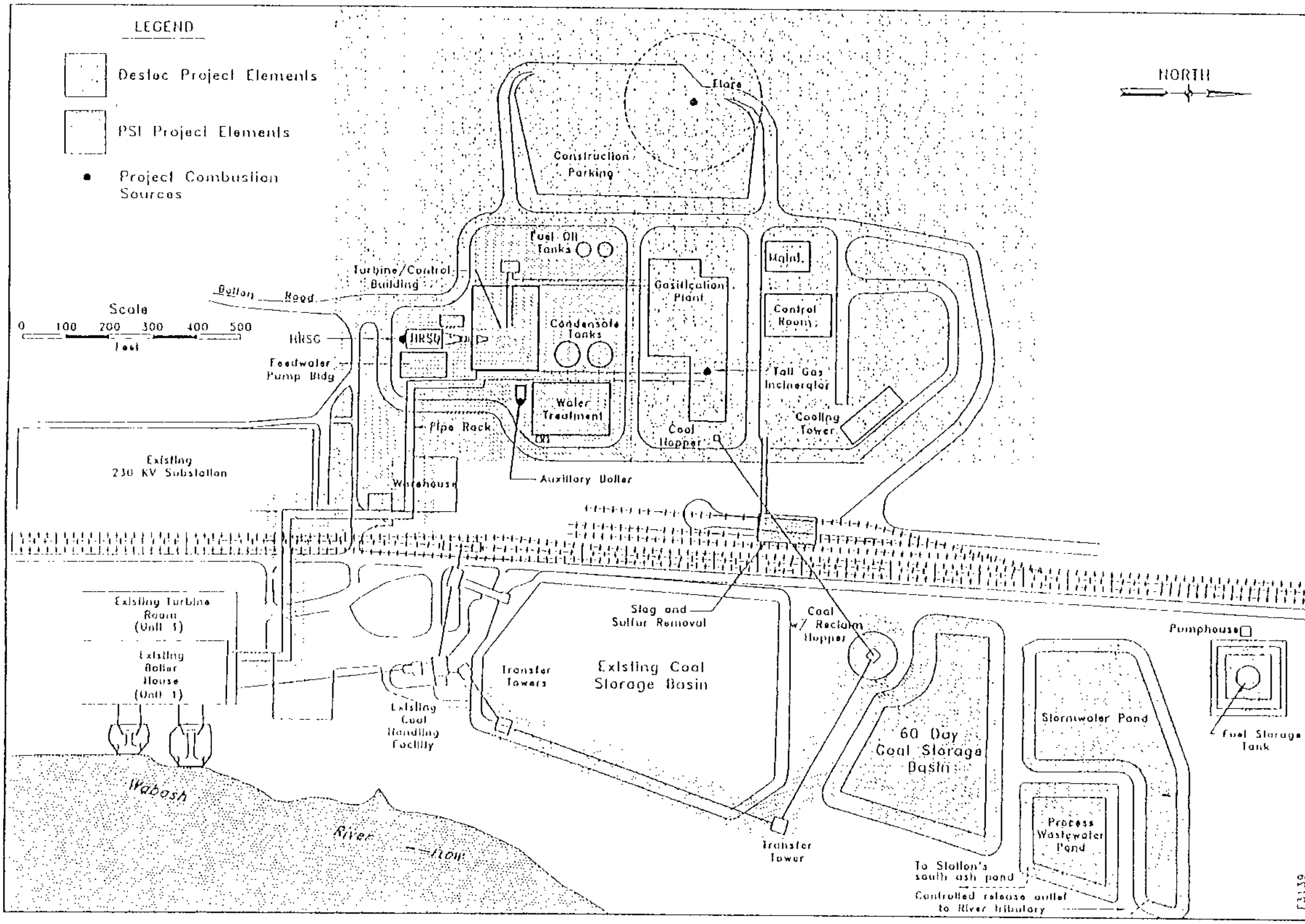


Figure 3 Project Plot Plan

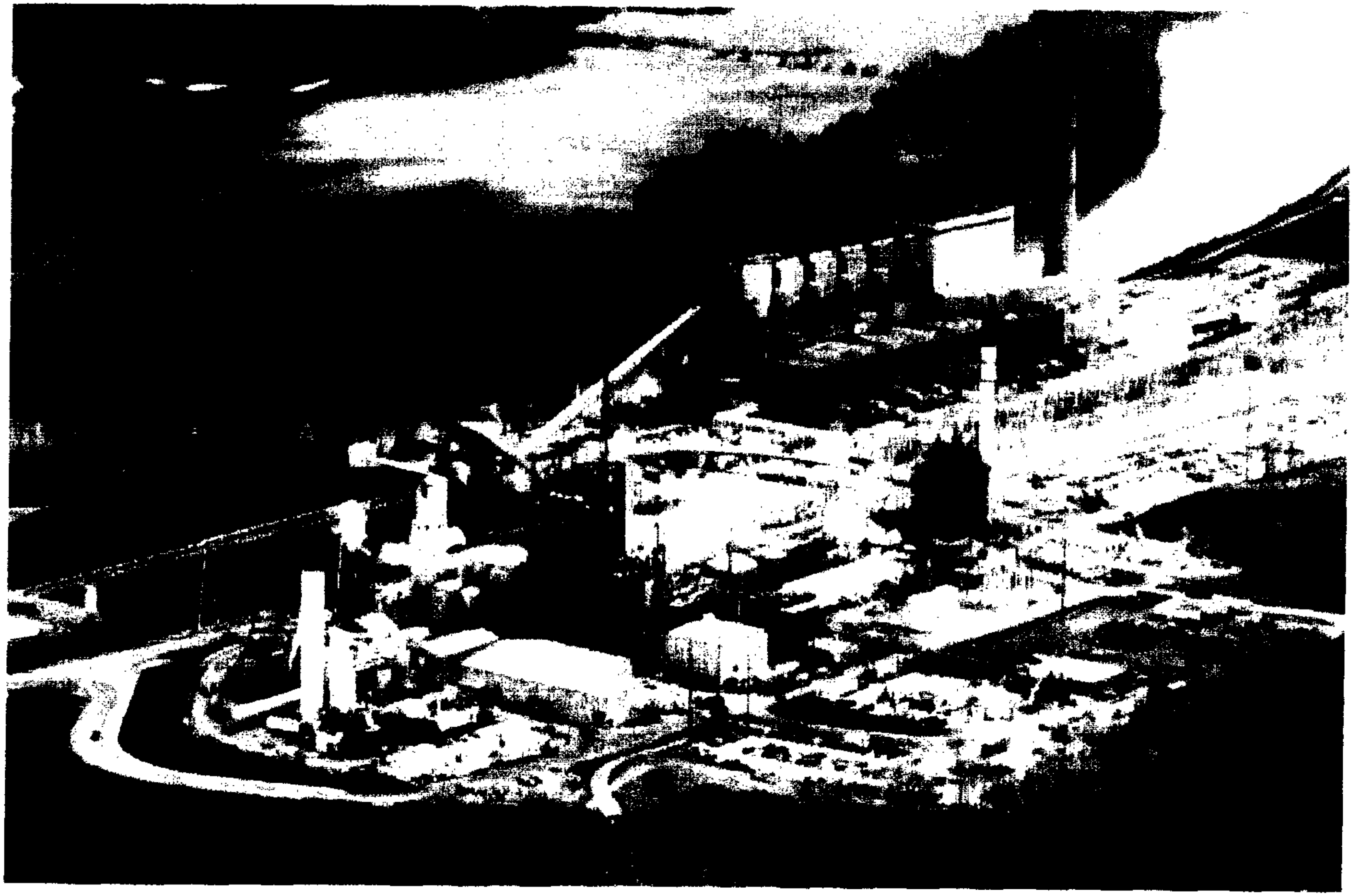


Figure 4

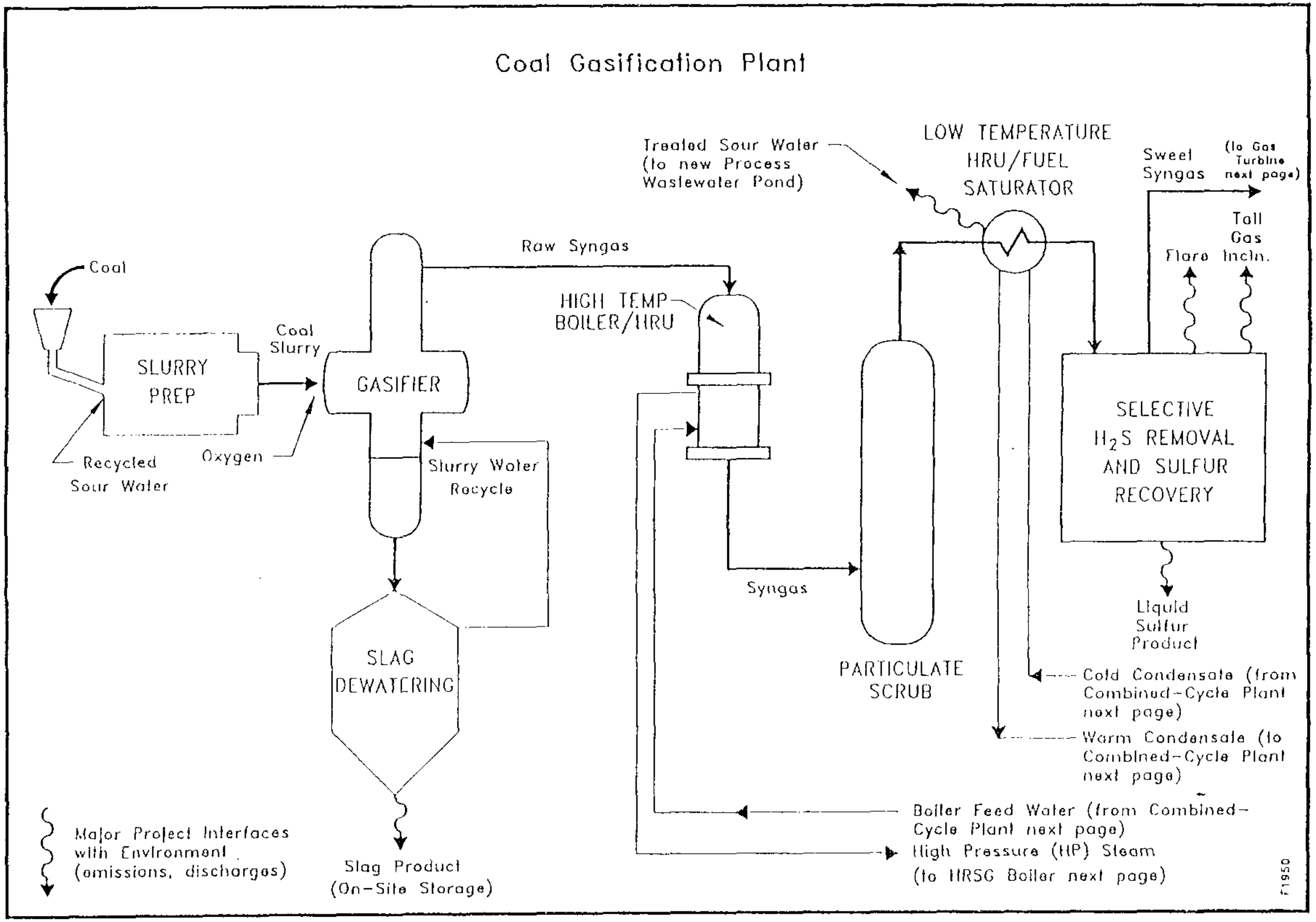


Figure 5 Conceptual CGCC Process Schematic

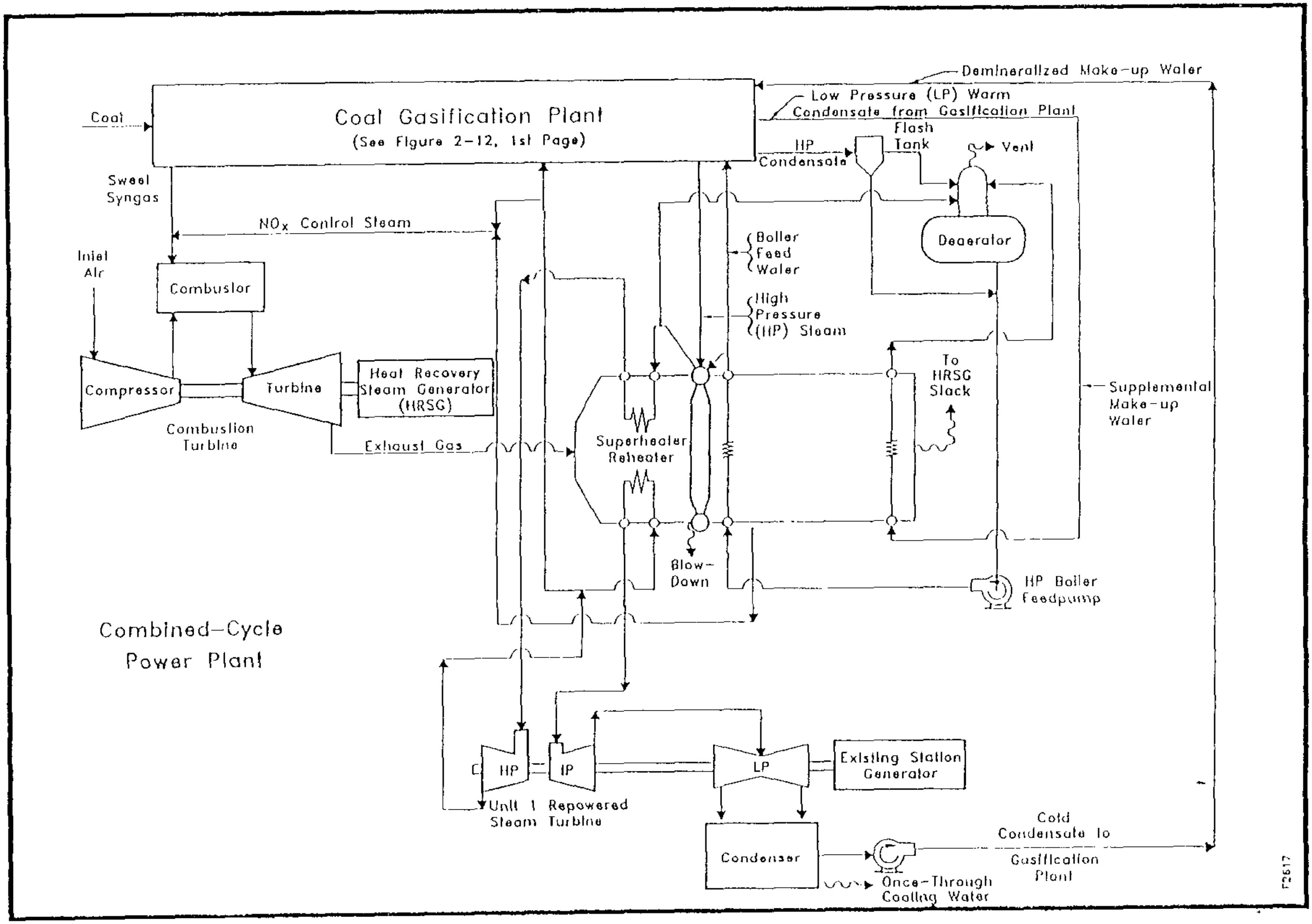


Figure 5A (Continued)

Block Flow Diagram

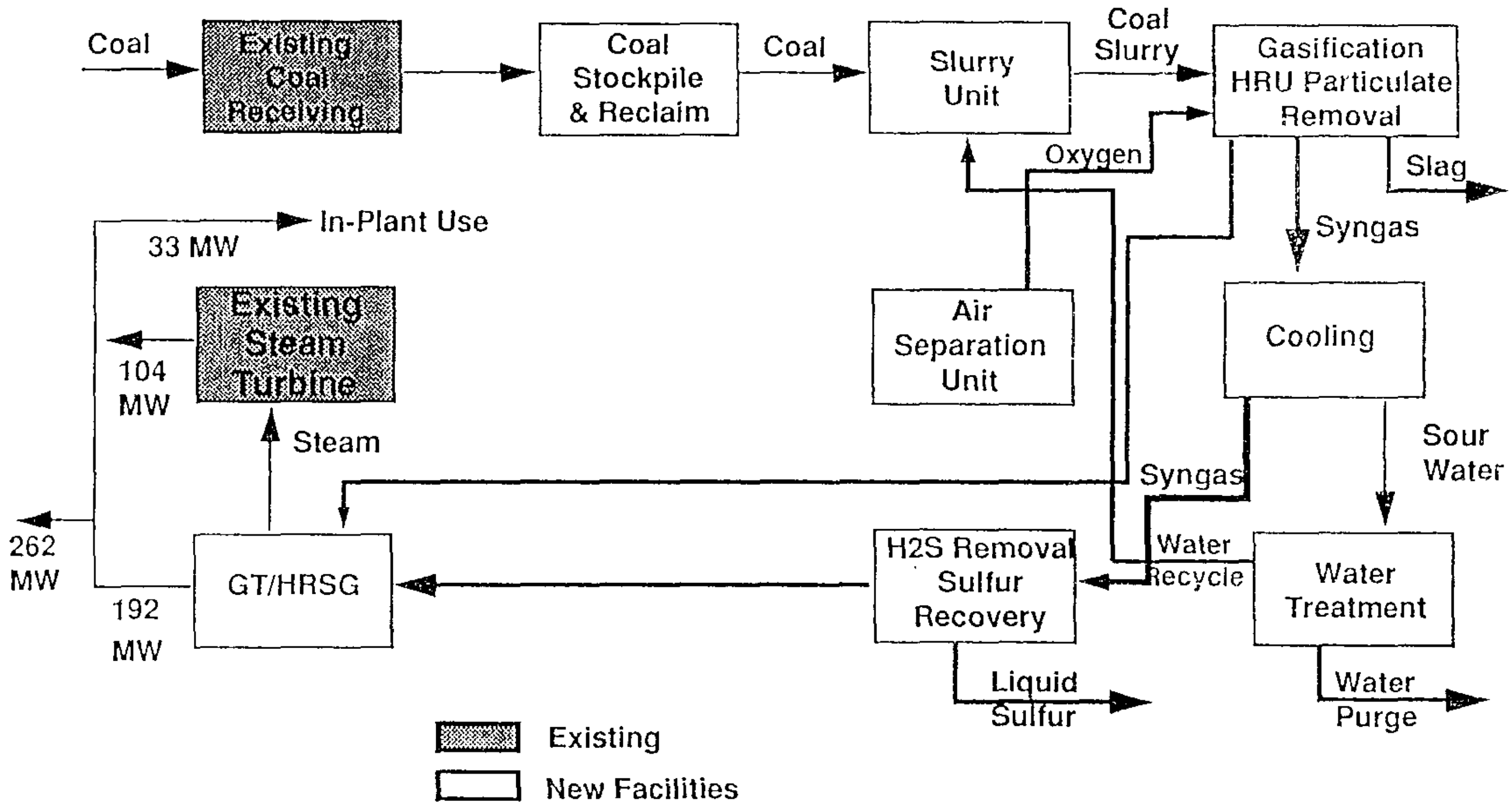


Figure 6

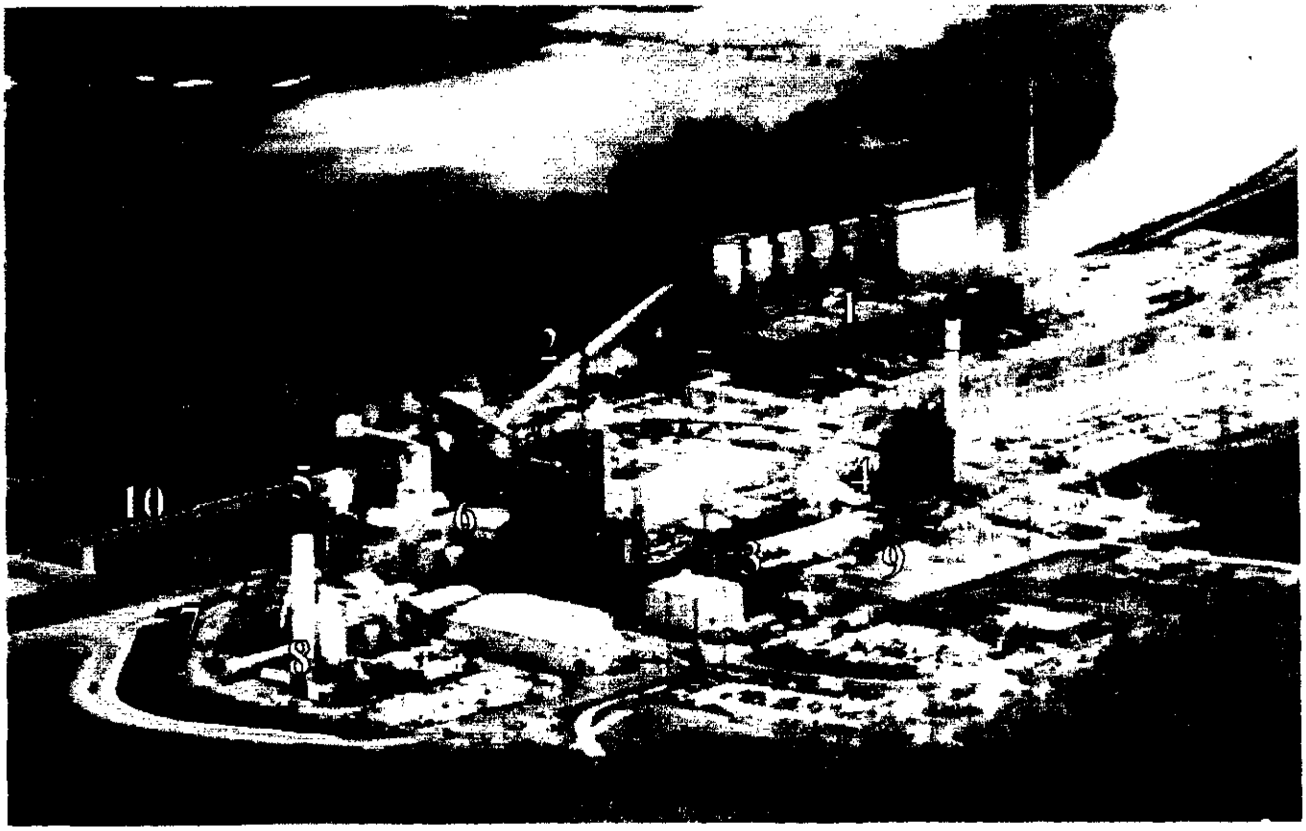


Figure 7

1. Existing Wabash Station
2. Existing coal transfer tower
3. Gas turbine building
4. Heat recovery steam generator
5. Coal receiving silo
6. Gasifier
7. Cooling Tower
8. Oxygen plant
9. New substation
10. Existing coal pile

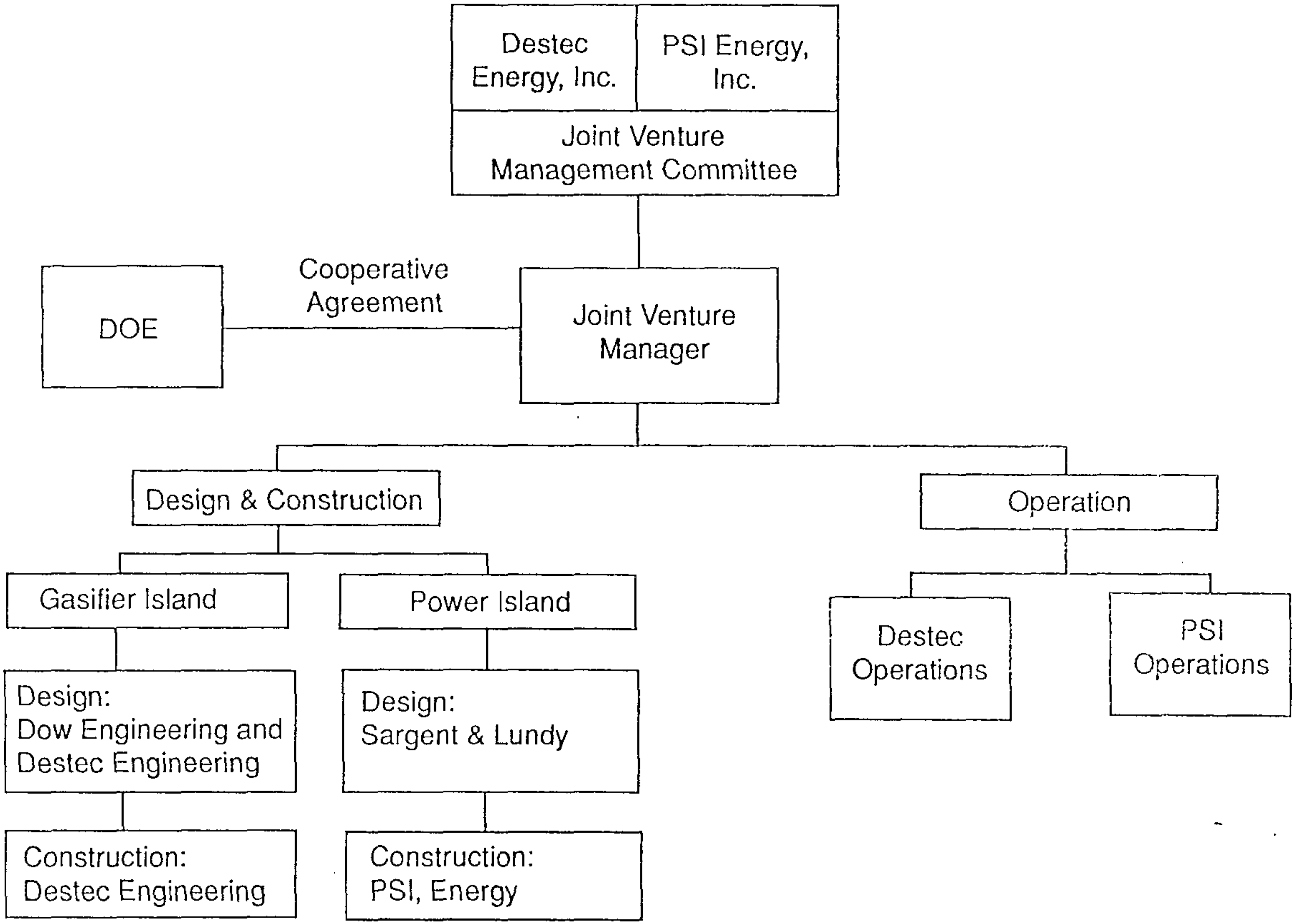


Figure 8 Project Organization

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan **Original Baseline**	Nov. 1993 Proj. Eval. Plan **Revised Baseline**	June 2, 1995 Contin. Appl'n **Revised Baseline**	May 1996 Proj. Mgmt. Plan **Current Baseline**	**Completion Date**
1.1.04	Signing of Gasification Services Agreement	06/24/92	06/24/92	06/24/92	06/24/92	06/24/92
1.1.05	Completion of Funding	03/15/92	11/19/92	11/19/92	11/19/92	11/19/92
1.1.06	Receipt of Air Permits	03/01/93	05/28/93	05/27/93	05/27/93	05/27/93
	Receipt of NPDES Permit Modifications	12/01/92	12/01/92	12/06/93	12/06/93	12/06/93
1.1.07	NEPA Completion	10/01/92	05/28/93	05/28/93	05/28/93	05/28/93
1.1.08	Receipt of IURC Certificate of Need	03/01/93	05/26/93	05/26/93	05/26/93	05/26/93
1.1.10	Project Management					
	Project Management Plan	10/31/92	12/04/92	12/04/92	12/04/92	12/04/92
	Financing Plan & Licensing Agreements	02/28/93	04/30/93	04/30/93	04/30/93	04/30/93
	Project Definition & Preliminary Plant Design	02/28/93	03/15/93	03/15/93	03/15/93	03/15/93
	Continuation Application	02/28/93	05/05/93	05/28/93	05/28/93	05/28/93
	Formal Project Review	03/15/93	03/30/93	03/30/93	03/30/93	03/30/93
	Draft Environmental Monitoring Plan	04/30/93	03/31/93	03/31/93	03/31/93	03/31/93
1.1.13	DOE Award	07/27/92	07/27/92	07/27/92	07/27/92	07/27/92
1.1.30	Award of EPC Subcontract for Oxygen Plant	11/15/92	12/15/92	12/15/92	12/15/92	12/15/92
1.2.01	Project Management					
	Environmental Monitoring Plan	06/30/93	06/30/93	07/28/93	07/28/93	07/28/93
	40% Completion Formal Project Review	06/30/94	06/30/94	04/05/94	04/05/94	04/05/94
	90% Completion Formal Project Review	04/30/95	04/30/95	03/09/95	03/09/95	03/09/95
	Final Public Design Report	07/31/95	01/31/95	07/01/95	07/01/95	07/07/95
	Test Plan	05/25/95	05/25/95	07/01/95	07/01/95	07/08/95
	Plant Startup Plan	07/31/95	07/31/95	05/25/95	05/25/95	05/25/95

Figure 9

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan **Original Baseline**	Nov. 1993 Proj. Eval. Plan **Revised Baseline**	June 2, 1995 Contin. Appl'n **Revised Baseline**	May 1996 Proj. Mgmt. Plan **Current Baseline**	**Completion Date**
	Continuation Application	07/31/95	01/31/95	06/02/95	06/02/95	06/02/95
1.2.04	Start of On-Site Dirtwork	12/01/92	06/01/93	06/01/93	06/01/93	06/01/93
	Release of Gasification Plant Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.05	Mobilization to Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.20	Award of High Temperature Heat Recovery Unit	11/01/92	11/03/92	11/03/92	11/03/92	11/03/92
	Award of Gasifier Vessels	01/10/93	01/21/93	01/21/93	01/21/93	01/21/93
	Jobsite Reciept of HTHRU	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Jobsite Reciept of Gasifier	07/01/94	07/01/94	05/15/94	05/15/94	05/15/94
1.2.22	Start of Foundation Work	09/15/93	10/08/93	10/08/93	10/08/93	10/08/93
	Setting of First Gasifier	09/01/94	09/01/94	06/08/94	06/08/94	06/08/94
	Setting of Second Gasifier	11/01/94	11/01/94	06/14/94	06/14/94	06/14/94
	Start of Refractory Installation	09/15/94	09/15/94	08/10/94	08/10/94	08/10/94
	Initial Firing with Coal	08/15/95	07/01/95	07/01/95	07/01/95	08/17/95
	Initial Delivery of Syngas	08/15/95	07/01/95	07/01/95	07/01/95	08/25/95
1.2.29	Completion of 100 Hour Test	10/01/95	08/15/95	08/15/95	11/18/95	11/18/95
1.2.30	Jobsite Receipt of Main Air Compressor	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Setting of Column	08/01/94	08/01/94	03/30/94	03/30/94	03/30/94
	Delivery of Oxygen	07/15/95	07/01/95	06/19/95	06/19/95	06/14/95
1.2.43	Construction Power/Water Available	09/01/93	10/06/93	10/20/93	10/20/93	10/20/93
1.2.50	Award of Coal Handling Subcontract	04/01/93	09/03/93	09/03/93	09/03/93	09/03/93
	Delivery of Coal to Syngas Facility	07/15/94	01/15/95	05/18/95	05/18/95	05/18/95
1.2.60	Award of STG Modification Subcontract	01/01/93	01/01/93	06/04/93	06/04/93	06/04/93

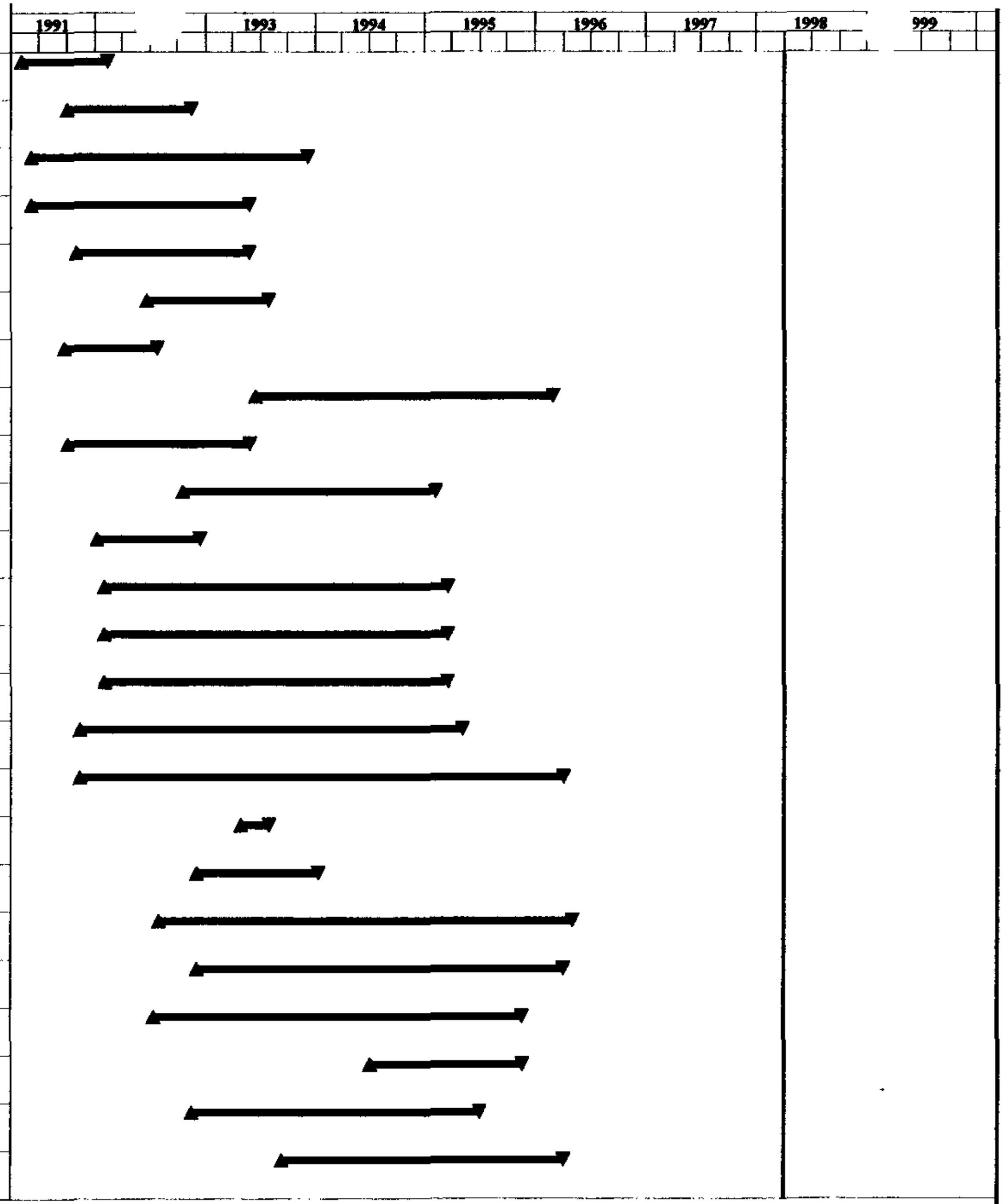
WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan **Original Baseline**	Nov. 1993 Proj. Eval. Plan **Revised Baseline**	June 2, 1995 Contin. Appl'n **Revised Baseline**	May 1996 Proj. Mgmt. Plan **Current Baseline**	**Completion Date**
1.2.70	Award of Gas Turbine Generator (GTG)	01/31/92	01/31/92	01/31/92	01/31/92	01/31/92
	Award of Heat Recovery Steam Generator (HRSG)	10/15/92	10/15/92	10/15/92	10/15/92	10/15/92
	Jobsite Delivery of GTG	03/01/94	01/01/94	03/18/94	03/18/94	03/18/94
1.2.75	Hydrotest of HRSG	04/15/95	04/15/95	03/31/95	03/31/95	03/31/95
	Synchronization of GTG	05/15/95	01/15/95	06/07/95	06/07/95	06/10/95
1.2.81	GTG Operation on Oil	01/01/95	01/01/95	06/07/95	06/07/95	06/09/95
	GTG Operation on Syngas	05/15/95	08/15/95	08/15/95	10/03/95	10/03/95
1.3.01	Project Management					
	Startup and Modification Report	12/01/95	12/01/95	11/01/95	01/01/99	
	Project Management Plan Update		not represented	11/01/95	05/01/96	05/16/96
	Formal Project Reviews	Annual				
	Draft Final Technical Report	07/31/98	07/31/98	09/30/98	01/01/99	
	Technology Performance & Economic Evaluation	11/30/98	11/30/98	10/01/98	02/01/99	
	Final Technical Report	12/31/98	12/31/98	11/30/98	02/28/99	

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
1010	OVERALL PROJECT - SCOPE DEFINITION	100	01MAY91A	14FEB92A
1050	FINANCE/FUNDING	100	01OCT91A	15NOV92A
1060	PERMIT PREPARATION & SUBMITTAL	100	07JUN91A	06DEC93A
1070	NEPA PROCESS	100	07JUN91A	28MAY93A
1080	IURC APPROVAL	100	01NOV91A	26MAY93A
1100	PROJECT MANAGEMENT/ENVIRONMENTAL PLANS	100	19JUN92A	30JUL93A
1130	DOE COOPERATIVE AGREEMENT	100	16SEP91A	27JUL92A
1140	PROCESS CONSULTANTS & FEES	100	15JUN93A	29FEB96A
1200	GASIFICATION PLANT PROCESS DESIGN	100	01OCT91A	30MAY93A
1220	GASIFICATION PLANT AREA DESIGN	100	15OCT92A	01FEB95A
1300	OXYGEN PLANT PACKAGE DESIGN	100	10JAN92A	15DEC92A
1400	UTILITIES DESIGN	100	02FEB92A	15MAR95A
1500	COAL HANDLING DESIGN	100	01FEB92A	15MAR95A
1600	REPOWERING DESIGN	100	01FEB92A	15MAR95A
1700	GAS TURBINE AREA DESIGN	100	12NOV91A	01MAY95A
1900	POWER GENERATION PROJECT MGMT/COMMON ENGS	100	12NOV91A	01APR96A
2010	PROJECT MANAGEMENT PLAN	100	01MAY93A	30JUL93A
2040	SITE PREPARATION	100	01DEC92A	14JAN94A
2050	GASIFICATION PLANT CONST MANAGEMENT	100	01AUG92A	01MAY96A
2060	GAS TURBINE AREA CONSTRUCTION MANAGEMENT	100	01DEC92A	01APR96A
2150	GP PRE-OPERATIONS MANAGEMENT	100	12JUL92A	18NOV95A
2160	GT SELECTION & TRAINING PLANT OPERATORS	100	30JUN94A	18NOV95A
2200	GASIFICATION PLANT EQUIPMENT PROCUREMENT	100	15NOV92A	30JUN95A
2220	GASIFICATION PLANT CONSTRUCTION	100	13SEP93A	01APR96A



Project Start 01JUN91
Project Finish 01JUN98
Data Date 31MAR98
Run Date 11MAR99

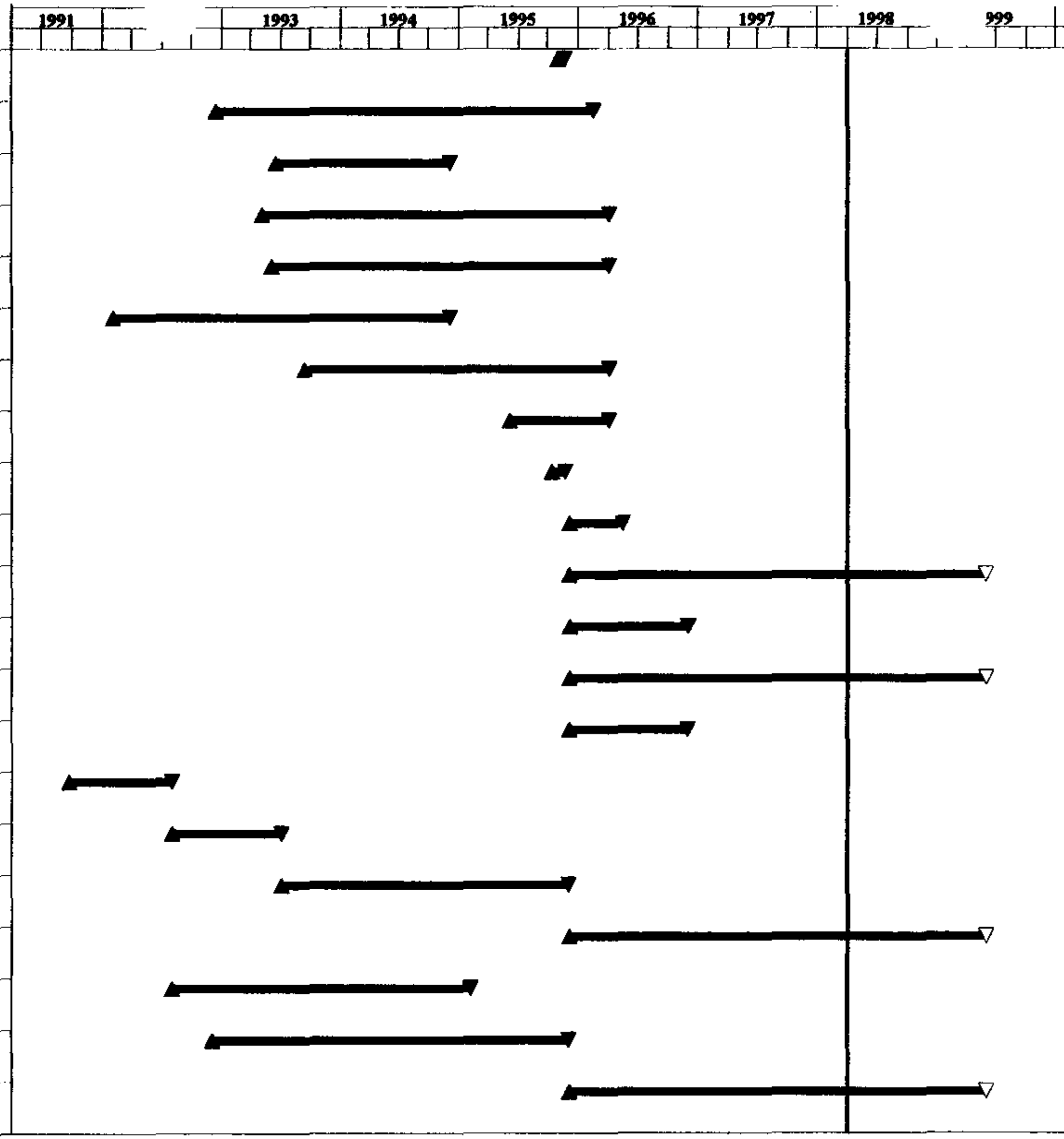
Early Bar
Progress Bar
Critical Activity

8216

Sheet 1 of 2

DESTEC ENGINEERING, INC.
WABASH RIVER COAL GASIF REPOWER PROJ
DOE PROJECT PLAN

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
2290	GAS PLANT ACCEPTANCE TESTING	100	25OCT95A	18NOV95A
2300	OXYGEN PLANT PROCUREMENT & CONSTRUCTION	100	15DEC92A	17FEB96A
2430	UTILITIES CONSTRUCTION	100	14JUN93A	01DEC94A
2500	COAL HANDLING PROCUREMENT & CONSTRUCTION	100	03MAY93A	01APR96A
2600	REPOWERING PROCUREMENT & CONSTRUCTION	100	04JUN93A	01APR96A
2700	GT AREA EQUIPMENT PROCUREMENT	100	31JAN92A	30NOV94A
2750	GAS TURBINE AREA CONSTRUCTION	100	13SEP93A	01APR96A
2810	GAS TURBINE ACCEPTANCE TESTING	100	01JUN95A	01APR96A
2990	PLANT PERFORMANCE TESTING	100	11OCT95A	18NOV95A
3010	PROJECT MANAGEMENT PLAN UPDATE	100	01DEC95A	16MAY96A
3060	ENVIRONMENTAL REPORTING	67	01DEC95A	01JUN99
3130	WARRANTY ADMINISTRATION	100	01DEC95A	02DEC96A
3140	GP COMMERCIAL OPERATION - DEMONSTRATION PERIOD	67	01DEC95A	01JUN99
3240	GT COMMERCIAL OPERATION - DEMONSTRATION PERIOD	100	01DEC95A	02DEC96A
11301PD	PRE AWARD PERIOD	100	16SEP91A	01AUG92A
11311BP	1ST BUDGET PERIOD	100	01AUG92A	30JUN93A
20402BD	2ND BUDGET PERIOD	100	30JUN93A	30NOV95A
30403BD	3RD BUDGET PERIOD	67	01DEC95A	01JUN99
11312PD	PHASE I DESIGN	100	01AUG92A	01FEB95A
20403PD	PHASE II CONSTRUCTION	100	01DEC92A	30NOV95A
30514PD	PHASE III OPERATION	67	01DEC95A	01JUN99



PLANT OPERATION STATISTICS
1997

GASIFICATION PLANT

PERFORMANCE DATA

Coal Gas Efficiency	72.0%
Gasifier on Coal (Hours)	3,885
Gasification Plant Capacity Factor (Produced)	39.9%
Gasification Plant Capacity Factor (Delivered)	38.0%

PRODUCTION DATA

Syngas on Spec (MMBtu)	6,214,864
1600# Steam (Mlbs)	1,720,229
Sulfur (Mlbs)	17,213
Slag, Moisture Free (Mlbs)	51,418

DELIVERED PRODUCTION

Actual Syngas Delivered (MMBtu)	5,926,875
1600# Steam (Mlbs)	1,641,232

MATERIAL/ENERGY USED

Coal, Moisture Free (Tons)	359,294
Coal (MMBtu)	8,910,112
Intermediate Pressure Steam (Mlbs)	145,352
Electrical Power, Total (MWh)	260,094
Oxygen, (Tons)	328,599
Fuel Gas (Mlbs)	19,129

POWER PLANT

PERFORMANCE DATA

Combustion Turbine Operating Hours (Syngas)	3,701
Combustion Turbine Operating Hours (Total)	4,261
Steam Turbine Operating Hours	4,116

PRODUCTION DATA

Combustion Turbine Generator (MWH)	725,054
Steam Turbine Generator (MWH)	361,823

Figure 11

Appendix C
LISTING OF TECHNICAL PUBLICATIONS
(PUBLIC INFORMATION)

DATE	TITLE/SOURCE	AUTHOR(S)
January 1997	"Wabash River Coal Gasification Repowering Project - First Year Operating Experience" Presented at the Fifth Annual Clean Coal Technology Conference in Tampa, Florida	E.J. Troxclair (Destec) Jack Stultz (PSI)
February 1997	Coal Power Systems Technology Workshop Presentation	Phil Amick (Destec)
October 1997	"Operating Experience at the Wabash River Coal Gasification Repowering Project" Presented at the 1997 Gasification Technologies Conference in San Francisco, California	Richard Payonk (Destec)
October 1997	"Operating Experience at the Wabash River Coal Gasification Repowering Project" Presented at the Korea Electric Power Research Institute's 2nd IGCC Workshop in Seoul, South Korea	Phil Amick (Destec)

Appendix D
Run Documentation and Production Graphs

Run Documentation
2nd Commercial Year Downtime Analysis
Operational Run Periods for 1997
Monthly Plant Performance Data
1997 Cold Gas Efficiency
1997 Hours of Operation
1997 Gasifier Hours on Coal
1997 Produced Syngas
1997 1600# Steam Produced
1997 Sulfur Produced
1997 Slag Production
1997 Delivered Syngas
1997 Delivered #1600 LB Steam
1997 Feed to Gasifier
1997 Monthly Power Production
1997 Energy Utilization (Gasifier)
1997 Electrical Energy Utilization
1997 Coal Feed to Gasifier
1997 Total Sulfur Emissions
1997 Pounds of SO2/MMBtu of Coal Feed

RUN DOCUMENTATION

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
JAN97A	1/1/97 00:00 Hours	1/2/97 00:22 Hours	24.37 Hours	Transferred off of coal operations to complete cleanout of ash deposition in waste heat boiler inlet channel and tubesheet.
JAN97B	1/4/97 21:37 Hours	1/5/97 02:32 Hours	4.92 Hours	Transferred off of coal operations due to high differential pressures within waste heat boiler.
JAN97C	1/7/97 04:09 Hours	1/10/97 07:59 Hours	75.83 Hours	Gasifier trip on low level in waste heat boiler high pressure steam drum caused by frozen BFW pressure transmitter B:AI(262).
JAN97D	1/10/97 11:42 Hours	1/10/97 21:47 Hours	10.08 Hours	Gasifier trip on low level in waste heat boiler high pressure steam drum caused by frozen BFW flow transmitter B:AI(105).
JAN97E	1/11/97 01:53 Hours	1/12/97 00:56 Hours	23.05 Hours	Transferred off of coal operations at PSI request due to failed hein joint on syngas feed valve to CT.
JAN97F	1/13/97 14:59 Hours	1/14/97 04:18 Hours	13.32 Hours	Gasifier trip off of coal operations due to high differential pressure across the V-157A-H back-up char filters. Primary system failure.
FEB97A	2/1/97 09:11 Hours	2/1/97 12:42 Hours	3.52 Hours	Transferred off of coal operations due to slag removal difficulties. Gasifier taphole plugged.
FEB97B	2/12/97 08:53 Hours	2/19/97 04:09 Hours	163.27 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler.

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
FEB97C	2/19/97 09:07 Hours	2/20/97 13:28 Hours	28.35 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler.
FEB97 C MAR97 A	2/20/97 20:13 Hours	3/6/97 20:01 Hours	335.8 Hours	Transferred off of coal operations due to failure of G-121A slag crusher gear fluid coupling.
MAR97 B	3/6/97 22:36 Hours	3/6/97 22:41 Hours	0.08 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler.
MAR97 C	3/6/97 23:30 Hours	3/7/97 01:37 Hours	2.12 Hours	Transferred off of coal operations at PSI request due to leak-by on a syngas feed control valve to the CT.
MAR97 D	3/7/97 16:08 Hours	3/7/97 18:55 Hours	2.78 Hours	Transferred off of coal operations due to flange leak and small syngas fire at Waste heat boiler 36" outlet spool piece.
MAR97 E	3/14/97 14:01 Hours	3/22/97 16:59 Hours	194.97 Hours	Transferred off of coal operation due to minor failure within BFW make-up line to the Rx Device CW System.
MAR97 F	3/29/97 14:11 Hours	3/29/97 17:28 Hours	3.28 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler.
MAR97 G APR97 A	3/29/97 21:54 Hours	4/8/97 10:03 Hours	228.15 Hours	Gasifier trip on low oxygen to fuel ratio due to loss of air flow to cold box during failure of DPU#1 multi-point fuse and subsequent oxygen delivery shortage

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
APR97B	4/10/97 07:09 Hours	4/11/97 02:55 Hours	19.77 Hours	Gasifier trip on low oxygen to fuel ratio due to unload of Oxygen Compressor after DPU#2 F3 fuse failure
MAY97 A	5/13/97 16:21 Hours	5/13/97 22:48 Hours	6.45 Hours	Transferred off of coal operations due to PSI CT Nox injection valve problems precluding acceptance of syngas
MAY 97B	5/14/97 21:57 Hours	5/15/97 00:56 Hours	2.98 Hours	Transferred off of coal operations for noise curtailment after PSI Ct NOX steam injection valves precluded acceptance of syngas.
MAY97 C	5/15/97 06:24 Hours	5/19/97 20:03 Hours	109.65 Hours	Transferred off of coal operations due to failure of B:AI(167) V-155B dP transmitter tubing failure
MAY97 D	5/19/97 23:58 Hours	5/27/97 22:36 Hours	190.63 Hours	Transferred off of coal operations due to failure of PSI CT Frame Blower
MAY97 E	5/29/97 06:58 Hours	5/29/97 09:25 Hours	2.45 Hours	Gasifier trip off coal operations due to main slurry feed flow instability induced by P-110A/B
JUN97A	6/1/97 09:58 Hours	6/1/97 11:52 Hours	1.90 Hours	Transferred off of coal operations due to slag removal difficulties. Gasifier taphole plugged.
JUN97B	6/11/97 13:03 Hours	6/18/97 22:11 Hours	177.13 Hours	Transferred off of coal operations due to PSI solenoid valve failure on CT Syngas feed valves.
JUN97C	6/19/97 09:45 Hours	6/22/97 21:09 Hours	83.40 Hours	Transferred off of coal operations due to high differential pressure in chloride scrubbing system packing.

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
JUL97A	7/13/97 14:25 Hours	7/13/95 20:47 Hours	6.37 Hours	Transferred off coal due to the syngas leak on the extraction gas flow meter, A:AI(479).
JUL97B	7/14/97 09:35 Hours	7/18/97 08:44 Hours	95.15 Hours	Gasifier trip off coal operations due to main slurry feed flow instability induced by P-110A/B.
JUL97C AUG97 A	7/20/97 12:59 Hours	8/4/97 14:32 Hours	361.55 Hours	Gasifier tripped on low O2:coal ratio due to loss of oxygen. Loose fuse in ASU caused oxygen vent valves to open.
AUG97 B	8/4/97 20:24 Hours	8/11/97 01:26 Hours	149.03 Hours	Transferred off of coal operation due to high sulfur in the product gas. C-170 tray damage and faulty product gas analyzer contributed.
AUG97 C	8/11/97 15:06 Hours	8/26/97 04:42 Hours	349.60 Hours	Transferred off of coal operation due to high boiler differential pressure and high boiler outlet temperature.
SEP97A	9/13/97 14:11 Hours	9/13/97 14:29 Hours	0.30 Hours	Gasifier tripped on oxygen to coal ratio. Slurry magmeters were reading erroneously.
SEP97B	9/13/97 16:10 Hours	9/28/97 11:59 Hours	355.82 Hours	Gasifier tripped on loss of boiler feed water from PSI.
SEP97C OCT97 A	9/28/97 14:43 Hours	10/7/97 21:18	222.58 Hours	Transferred off coal operation due to high C-170 dp as a result of salt build up in the column.
OCT97 B	10/12/97 12:31	10/12/97 22:43	10.20	Transferred off coal operation due to failed M-120A slurry mixer.

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
NOV97 A	11/4/97 21:54	11/5/97 16:05	18.18	Manual trip of gasifier due to syngas leak on DO-119.
NOV97 B	11/6/97 17:17	11/9/97 5:35	60.31	Manual trip of gasifier due to slag grinder misalignment. Root cause identified as gasifier differential thermal growth.
NOV97 C	11/10/97 22:00	11/10/97 23:41	1.69	Manual trip of gasifier due to syngas leak on the inlet flange of the chloride scrubber, C-165.
NOV97 D	11/12/97 14:02	11/12/97 17:12	3.17	Manual trip of gasifier due to failed PSV on C-180 venting acid gas to the flare.
NOV97 E	11/14/97 19:46	11/21/97 18:45	166.98	Manual trip of gasifier at PSI's request. PSI unable to re-light combustion turbine after slurry mixer upset forced them off line earlier.
NOV97 F	11/22/97 9:16	11/22/97 16:48	7.52	Manual trip of gasifier due to high level in the dry char vessel, V-155A.
NOV97 G	11/23/97 2:10	11/26/97 3:55	73.74	Manual trip of gasifier due to high level in the dry char vessel, V-155A
NOV97 H	11/26/97 7:40	11/26/97 10:23	2.73	Manual trip of gasifier due to high level in the dry char vessel, V-155A.
NOV97I	11/26/97 19:46	11/28/97 8:07	36.35	Manual trip of gasifier due to plugged overflow line from slag hopper.
DEC97 A	12/19/97 16:17	12/20/97 7:00	14.72	Manual trip of gasifier due to syngas leak on dry char secondary filter, V-158G.
DEC97 B	12/20/97 16:15	12/30/97 17:39	241.40	Manual trip of gasifier due to failed decant filter in T-140C.

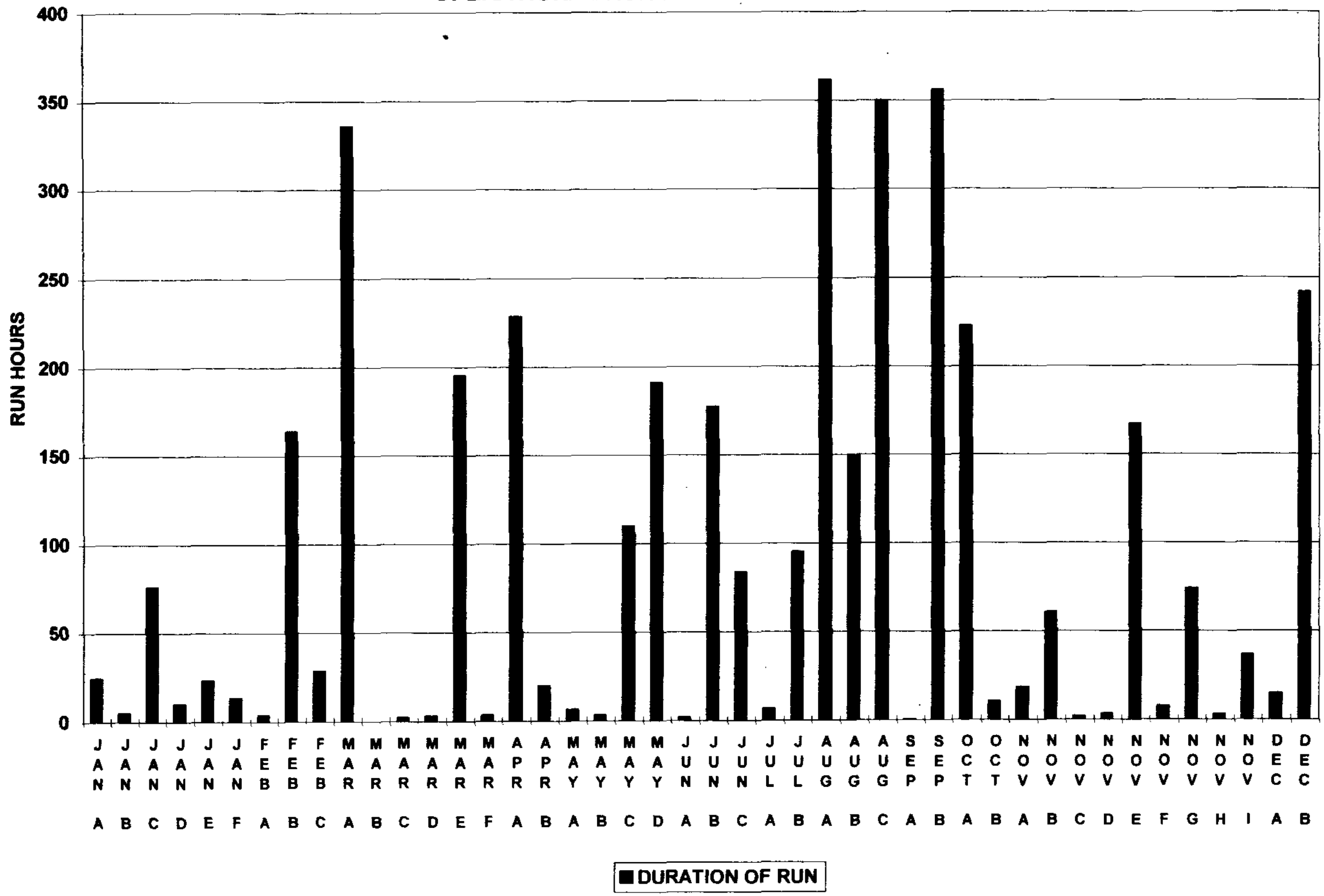
WRCGRP 2nd Commercial Year Downtime Analysis (Through November 30, 1997)

Principle Area	(sub-totals)	Attributable Downtime Hours	Percentage of Total Downtime	% of Total Downtime W/O SBOH
Stand-by Outage Hours (SBOH)		**1873**	**39.88%**	
CT Combustor Cans and Nozzles	515			
Pre-petcoke outage	354			
Post petcoke outage	63			
Taphole Plugging coal feed (pending)	244			
Taphole plugging (BFW Loss/Tube Failure)	208			
Slurry Feed System (pending)	86			
CT Valve Problems	81			
Steam piping failure	75			
Steam outage (pending – October)	79			
Steam outage (pending – September)	36			
Boiler Tube Failures	36			
Delays starting CT	37			
CT Frame Blower Failure	27			
BFW Loss	19			
Noise Curtailment (CT Valve Problems)	13			
Dry Char System		**706**	**15.02%**	**24.99%**
Pulse Valve and Vessel Refurbishing	260			
Element Corrosion	114			
High Element Resistance (plugging)	258			
Primary Vessel High Level	49			
Primary Vessel Inlet Valve Problems	24			
Low Temperature Heat Recovery System		**515**	**10.97%**	**18.26%**
C-165 Packing Deposition (tars)	249			
Chloride Scrubbing System Incident Damage Repair	220			
C-165 Inlet line gasket failure	38			
E-165 Rollout spool gasket failure	8			
Ash Deposition		**381**	**8.12%**	**13.50%**
E-150 Ash deposition	119			
PS-120, Horseshoe deposition	75			
High E-150 Outlet Temp and differential pressure	187			
High Temperature Heat Recovery Unit		**323**	**6.87%**	**11.43%**
Boiler Tube fouling and repair	96			
E-150 seal leg drain, DO-119 failure	25			
Spool and Flange leaks	202			
Scheduled Outages		**267**	**5.69%**	**9.46%**
Air Separation Unit		**198**	**4.21%**	**7.01%**
Planning/Scheduling		**157**	**3.35%**	**5.57%**
Spare Parts/Work Scheduling	63			
Missing V-155 gaskets	30			
Re-work Screen riser/piglet	17			
Dry Char/COS heat up	48			
Gasifier		**144**	**3.06%**	**5.09%**
D-122 Make-up system failure	79			
G-121 alignment/HR thermal growth	40			
Failed slurry mixer, M-120A	11			
Syngas leaks	13			
Acid Gas System		**59**	**1.26%**	**2.09%**
PSV-180 Failure	24			
C-170 not removing H2S, high differential pressure	14			
C-170 high differential pressure	16			

WRCGRP 2nd Commercial Year Downtime Analysis
(Through November 30, 1997)

Principle Area	(sub-totals)	Attributable Downtime Hours	Percentage of Total Downtime	% of Total Downtime W/O SBOH
Instrument Failure		37	0.78%	1.30%
Noise Curtailment (CT Valve Problems)		13	0.28%	0.46%
Slag System		12	0.26%	0.43%
Plugged Chokes	16			
Freeze Protection Failures		6	0.14%	0.23%
Sulfur Recovery Unit		5	0.11%	0.18%
Total Hours of Downtime		4696	100%	

OPERATIONAL RUN PERIODS FOR 1997



Monthly Plant Performance Data

	JAN	FEB	MAR	APR	MAY
PERFORMANCE DATA					
Coal Gas Efficiency	68.78	71.31	73.11	74.61	74.31
Gasifier on Coal (Hours)	151.15	390.94	393.38	197.85	311.66
PRODUCTION DATA					
Syngas on Spec (MMBtu)	198422.2	632819.3	663668.6	328199	507536.5
1600# Steam (Mlbs)	62445.2	169459.9	169046.5	84045	140810.5
Sulfur (Mlbs)	802	1253.5	1819.8	1113	1270.8
Slag, Moisture Free (Mlbs)	1786	5316.4	5472.9	2742.8	4315.7
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	160091.3	607035.3	633746.8	317328.3	478090.7
1600# Steam (Mlbs)	53890.4	166675.6	163834.1	82511.1	134278.4
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	14528.6	41709.1	42339.1	20503.1	32322.4
Coal (MMBtu)	311726	894911	908427.6	439914.6	693510.2
Intermediate Pressure Steam (Mlbs)	13084.7	16773.1	15820.8	7178.3	13330.5
Electrical Power, Total (MWh)	21373.3	21446.2	23717.2	12483.3	19312.3
Oxygen, (Tons)	11699.2	33338.5	34010	16868.3	27598.6
Fuel Gas (Mlbs)	1863	1392.3	1951	870.8	2036.1
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	102.51	123.13	109.71	104.37	87.95
Total SO2 Emissions (lbs)	35181.3	91311	79597.1	34067	48357.7
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.109	0.101	0.077	0.069	0.063
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	27105	72754	77071	39760	59145
Steam Turbine Generator (MWh)	12282	36843	37175	18501	30174
Total Gross Generation (MWh)	39387	109597	114246	58261	89319
Total Syngas Generation (MWh)	27830	27830	107338	53755	82957

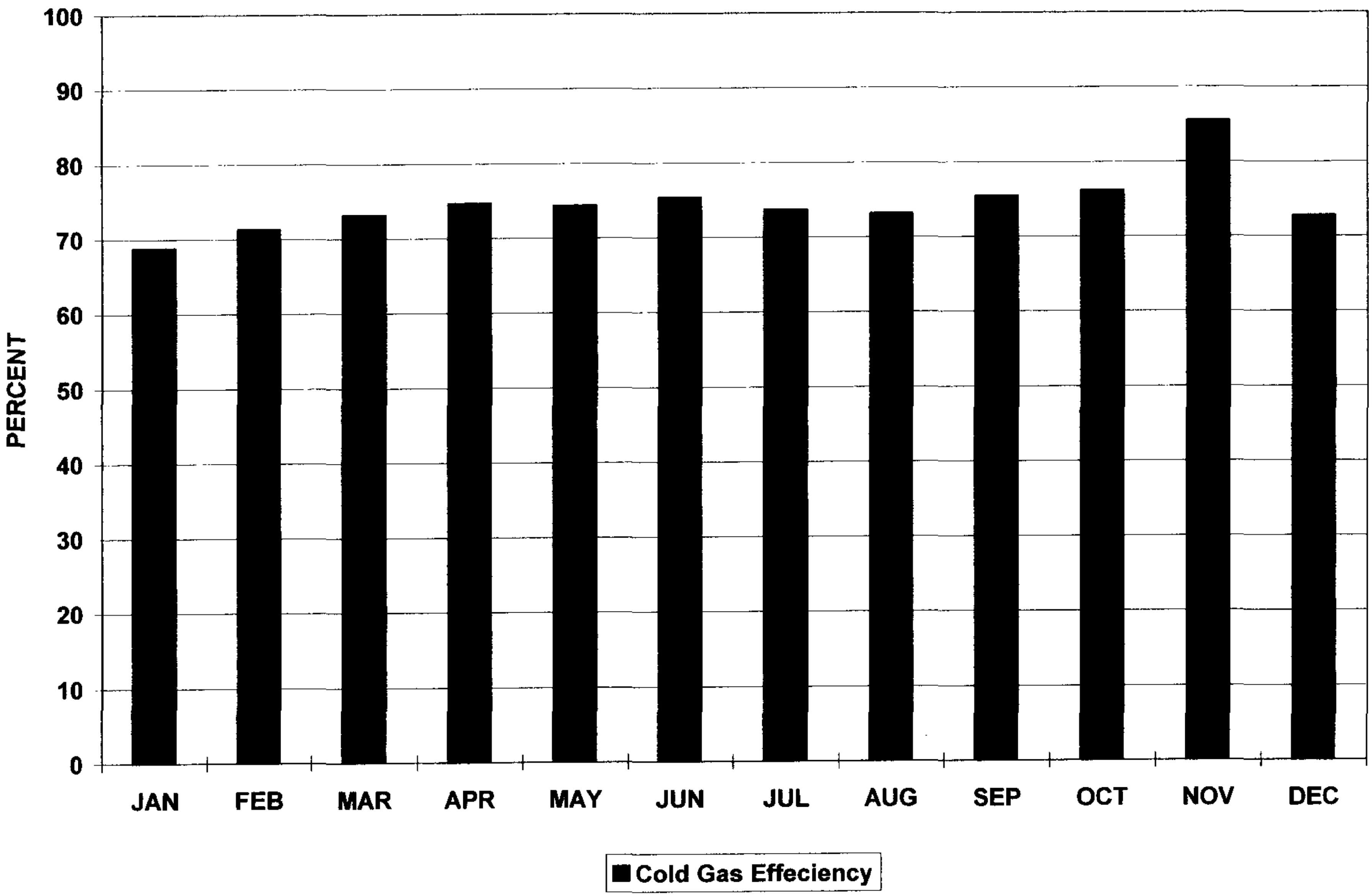
Monthly Plant Performance Data

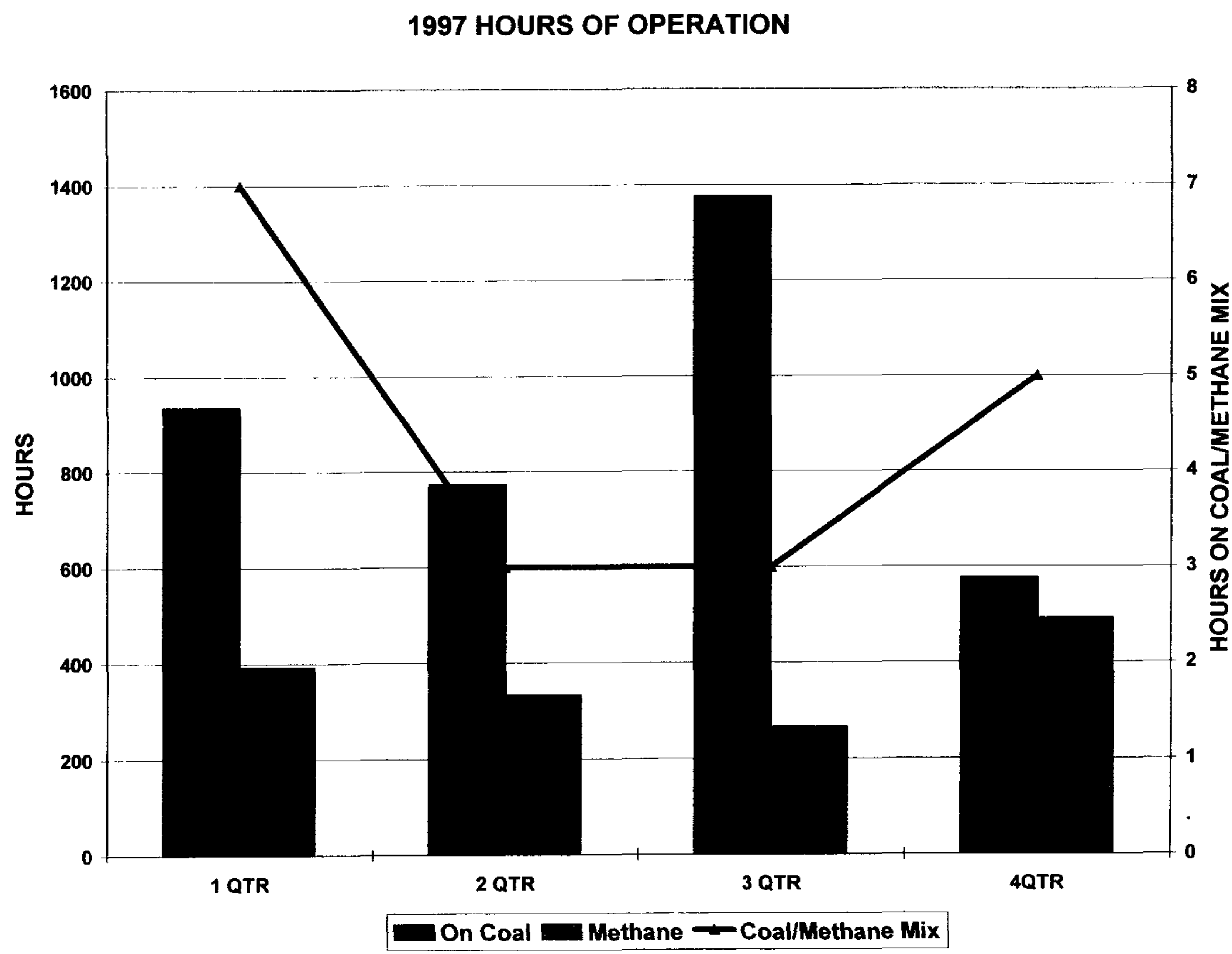
	JUN	JUL	AUG	SEP	OCT
PERFORMANCE DATA					
Coal Gas Efficiency	75.33	73.65	73.14	75.44	76.12
Gasifier on Coal (Hours)	262.33	376.68	585.2	413.39	175.54
PRODUCTION DATA					
Syngas on Spec (MMBtu)	426956.6	611182	959154.5	626836.7	258602.8
1600# Steam (Mlbs)	121731.5	176069.7	259996.5	182914.3	77590.4
Sulfur (Mlbs)	1112.4	1662.2	2549.8	1494.5	922.6
Slag, Moisture Free (Mlbs)	3474.7	5095.2	7951.5	5275.8	2188.3
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	406565.5	592472.3	936909.1	600515	249046.4
1600# Steam (Mlbs)	113389.2	174728.1	257471.4	171188.4	70244.9
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	26547.2	38756.3	61599.7	39409.1	15947.5
Coal (MMBtu)	569597.7	831554.5	1321684	845561.4	342170.2
Intermediate Pressure Steam (Mlbs)	12339.9	13573.9	16616.1	13770.3	8670.3
Electrical Power, Total (MWh)	22498.6	25472.4	25472.4	24650.8	22413.1
Oxygen, (Tons)	22316	32372.8	49357.5	33235.6	14374.9
Fuel Gas (Mlbs)	1722.7	1499.5	1418.9	1056.3	1475.5
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	120.95	151.06	170.03	224.51	200.97
Total SO2 Emissions (lbs)	60749.5	130027.3	211043.9	123107.6	61806
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.095	0.142	0.156	0.136	0.154
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	53235	70501	108784	70671	30132
Steam Turbine Generator (MWh)	26409	35912	55249	37350	16012
Total Gross Generation (MWh)	79644	106413	164033	108021	46144
Total Syngas Generation (MWh)	67781	99191	106411	101672	44042

Monthly Plant Performance Data

	NOV	DEC
PERFORMANCE DATA		
Coal Gas Efficiency	85.47	72.72
Gasifier on Coal (Hours)	370.89	255.95
PRODUCTION DATA		
Syngas on Spec (MMBtu)	572826.2	427659.9
1600# Steam (Mlbs)	156637.4	119472.4
Sulfur (Mlbs)	2116.6	1053.3
Slag, Moisture Free (Mlbs)	4337.2	3461.2
DELIVERED PRODUCTION		
Actual Syngas Delivered (MMBtu)	529646.9	415397.3
1600# Steam (Mlbs)	141423.4	111596.6
MATERIAL/ENERGY USED		
Coal, Moisture Free (Tons)	31306.1	27853.9
Coal (MMBtu)	671703	597632.7
Intermediate Pressure Steam (Mlbs)	14513.3	8961.2
Electrical Power, Total (MWh)	23282.6	18016.2
Oxygen, (Tons)	31360	22069.3
Fuel Gas (Mlbs)	1989.8	813.2
PLANT EMISSION DATA		
Average Total Sulfur in Syngas (ppm)	66.3	79.33
Total SO2 Emissions (lbs)	73649.3	69657.3
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.091	0.108
POWER PLANT PRODUCTION DATA		
Combustion Turbine Generator (MWh)	66918	48978
Steam Turbine Generator (MWh)	31639	24277
Total Gross Generation (MWh)	98577	73255
Total Syngas Generation (MWh)	75931	69437

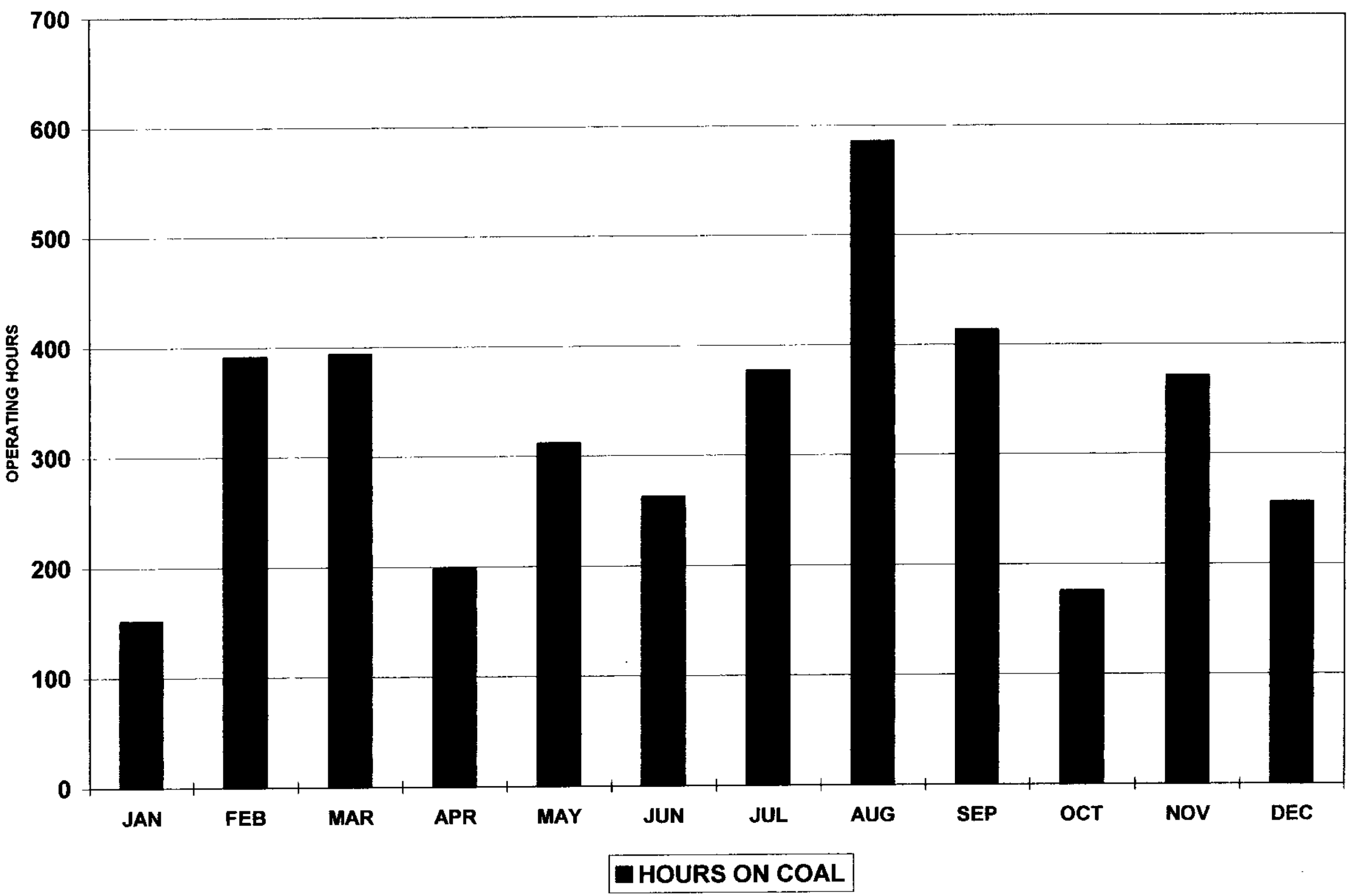
1997 COLD GAS EFFICIENCY



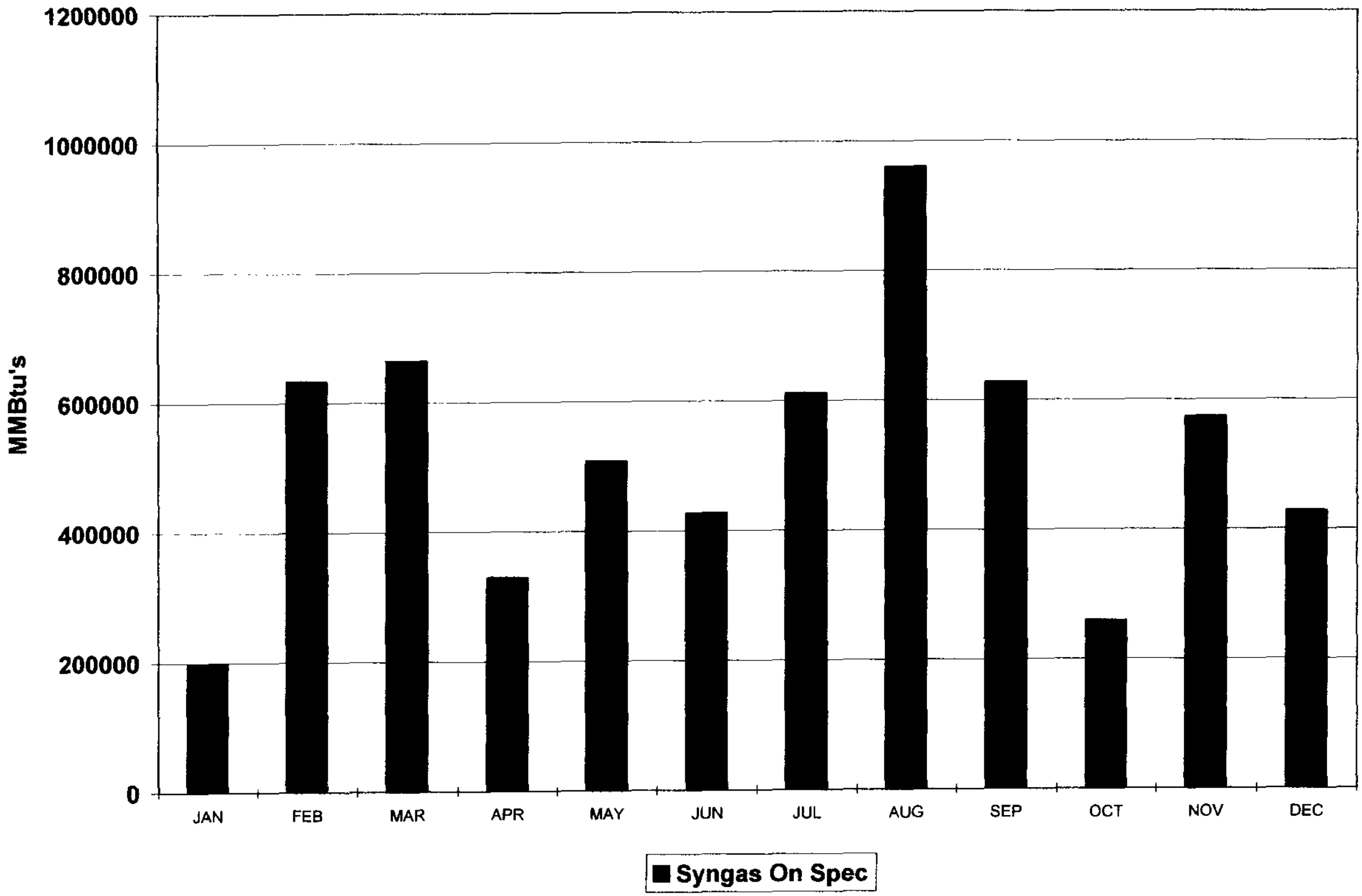


1997 HOURS OF OPERATION
HOURS
1600
1400
1200
1000
800
600
400
200
0
HOURS ON COAL/METHANE MIX
8
7
6
5
4
3
2
1
0
1 QTR
2 QTR
3 QTR
4QTR
On Coal
Methane
Coal/Methane Mix

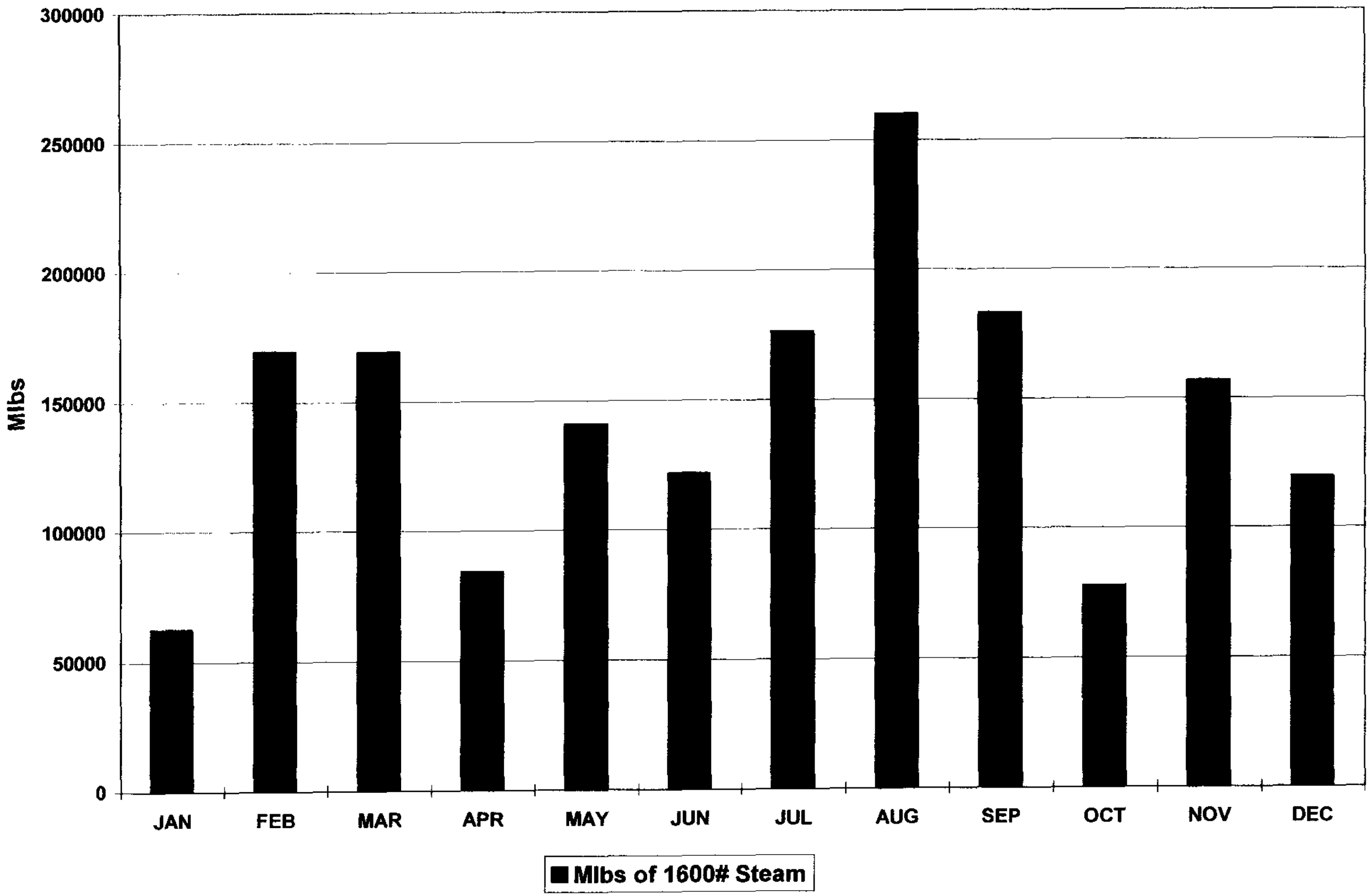
1997 GASIFIER HOURS ON COAL

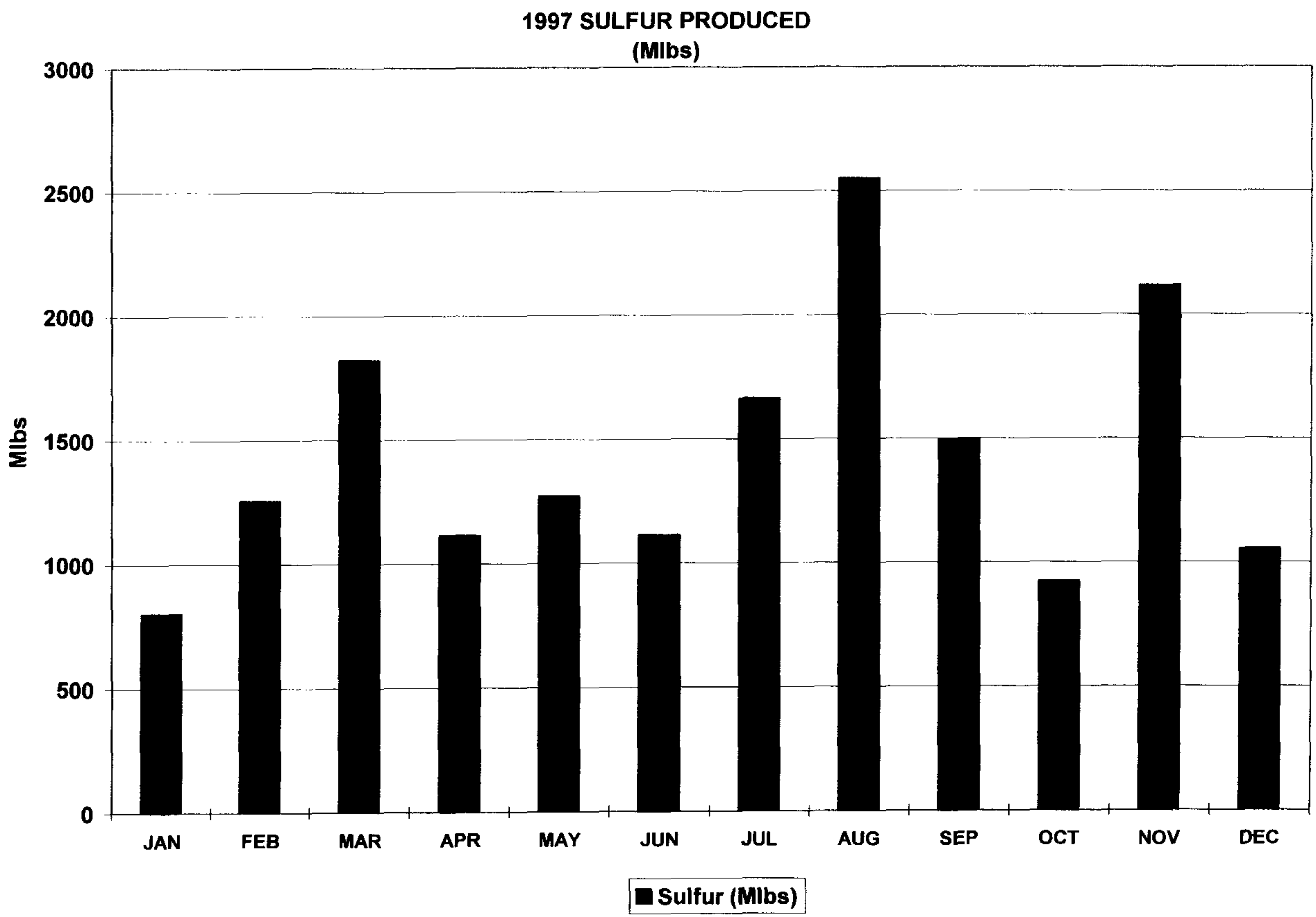


1997 PRODUCED SYNGAS
(ON-SPECIFICATION)

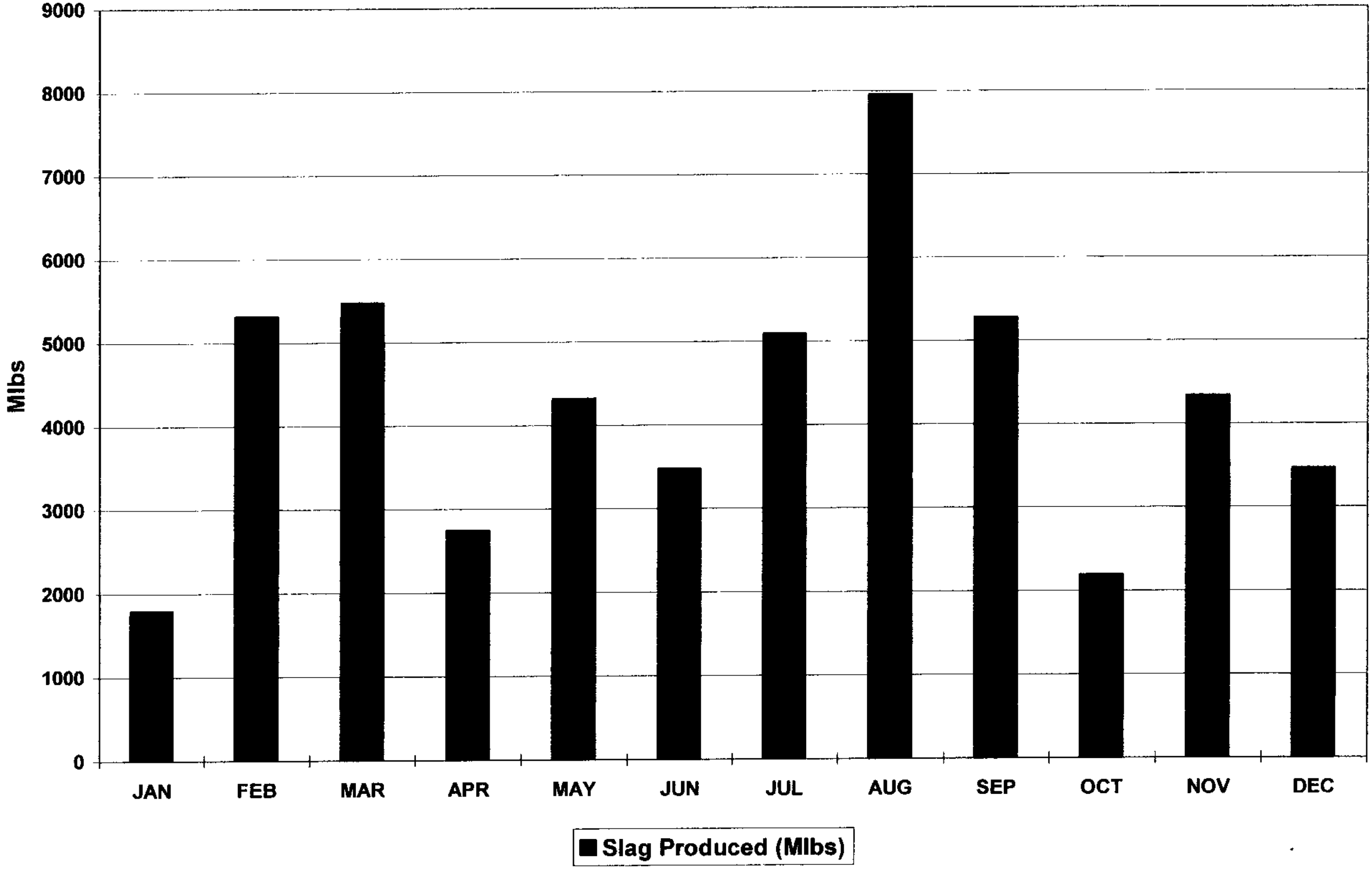


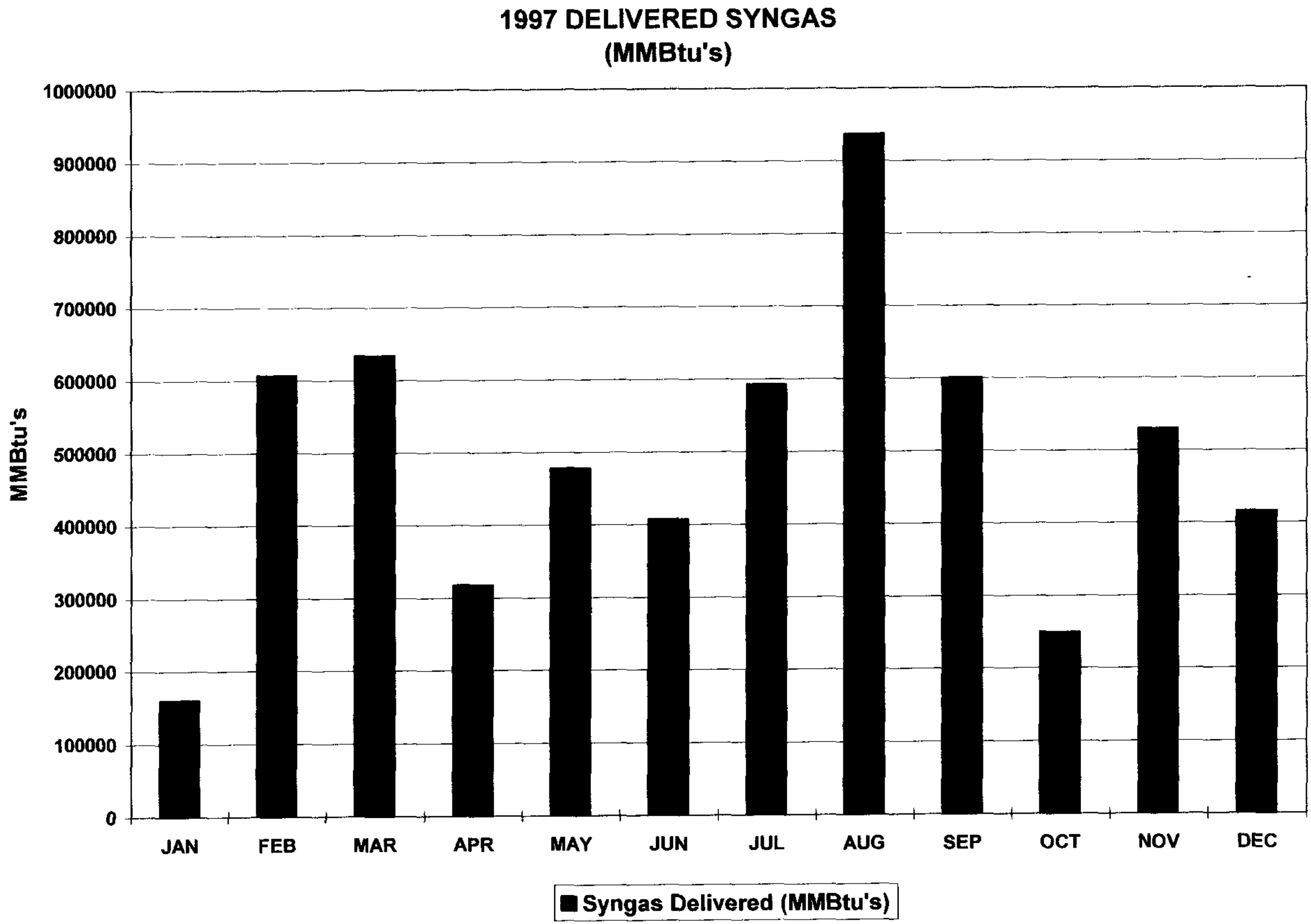
1997 1600# STEAM PRODUCED
(Mlbs)




1997 SULFUR PRODUCED
(Mlbs)
Mlbs
3000
2500
2000
1500
1000
500
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Sulfur (Mlbs)

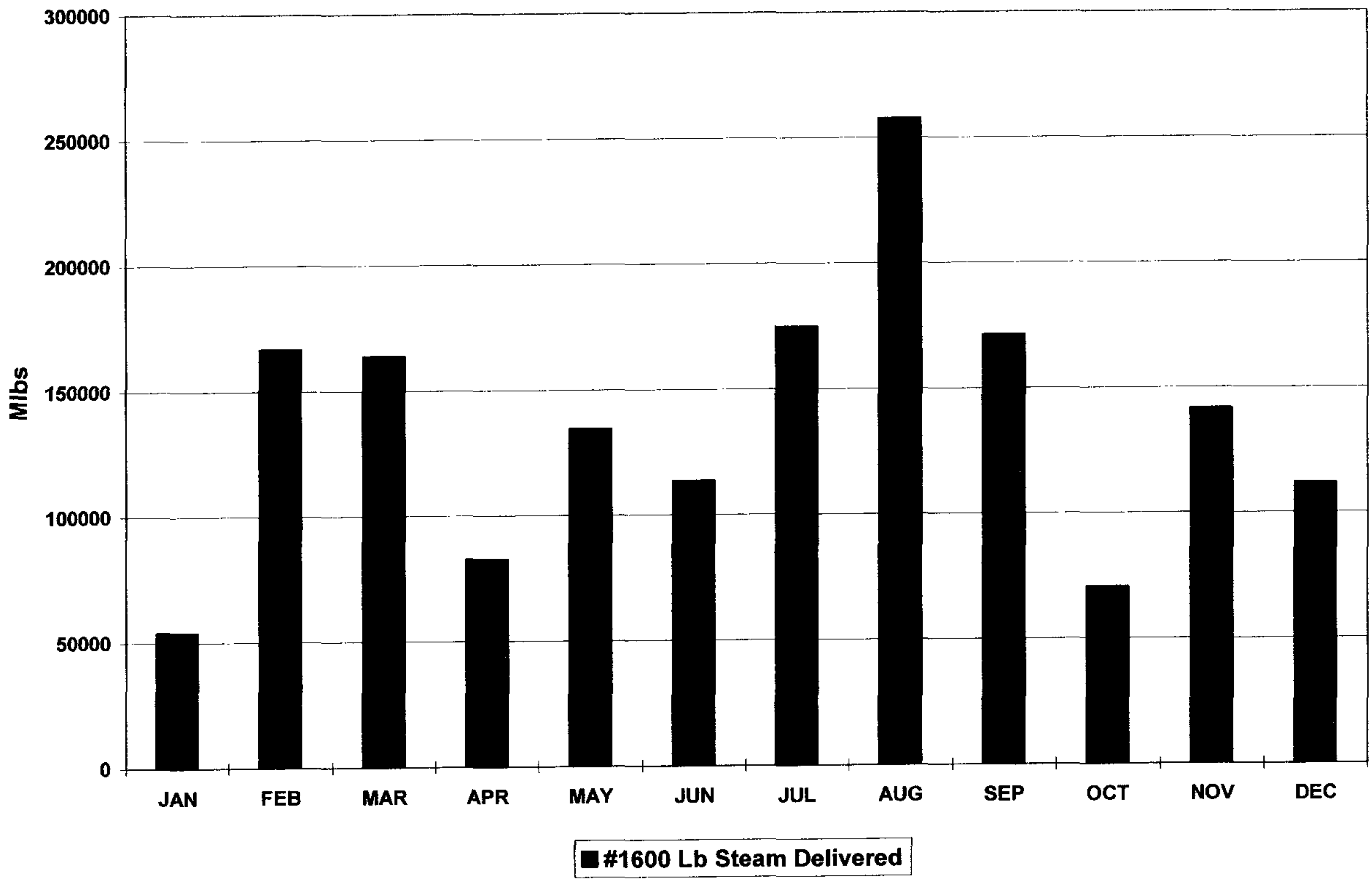
1997 SLAG PRODUCTION
(Mlbs - Moisture Free)

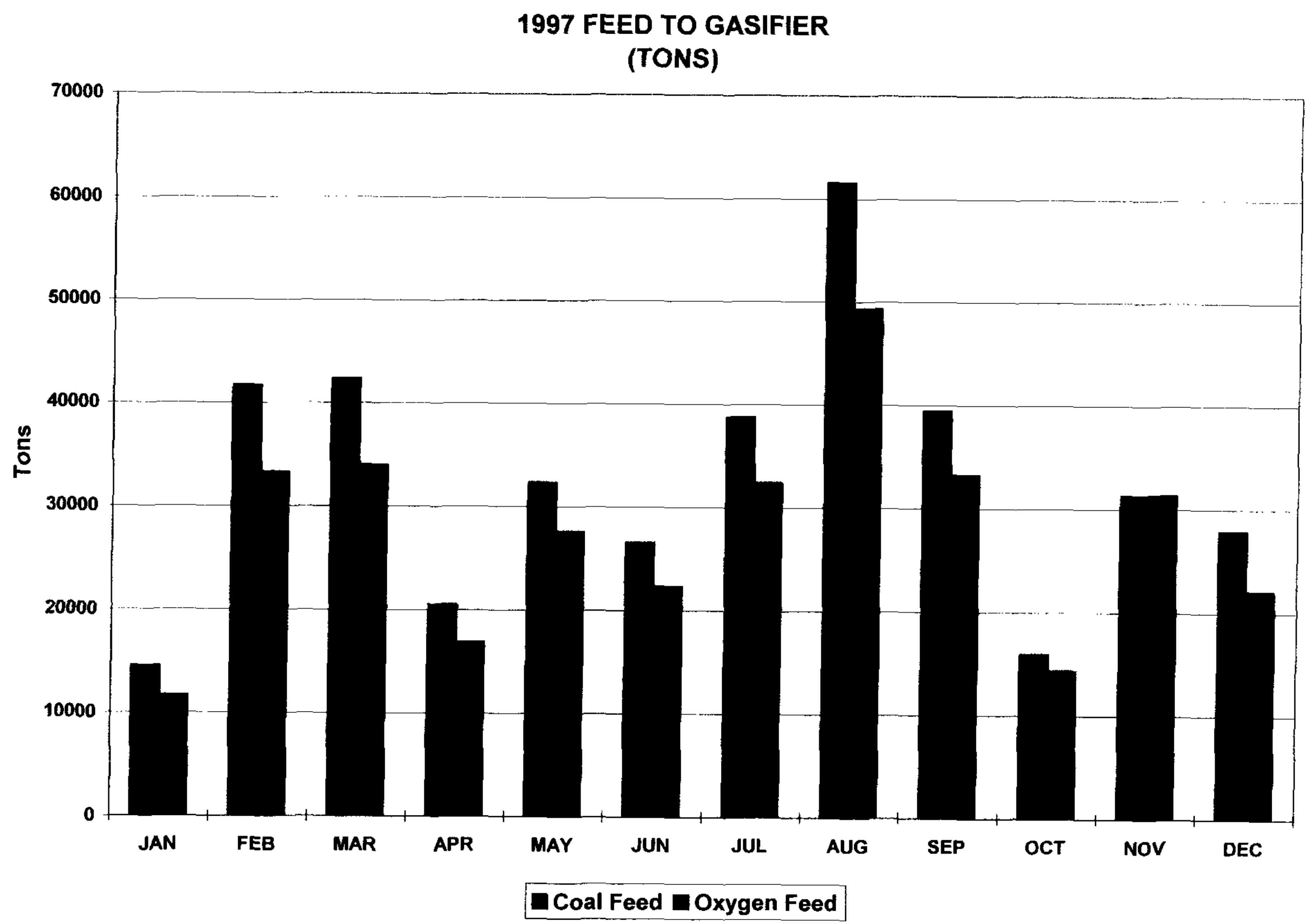


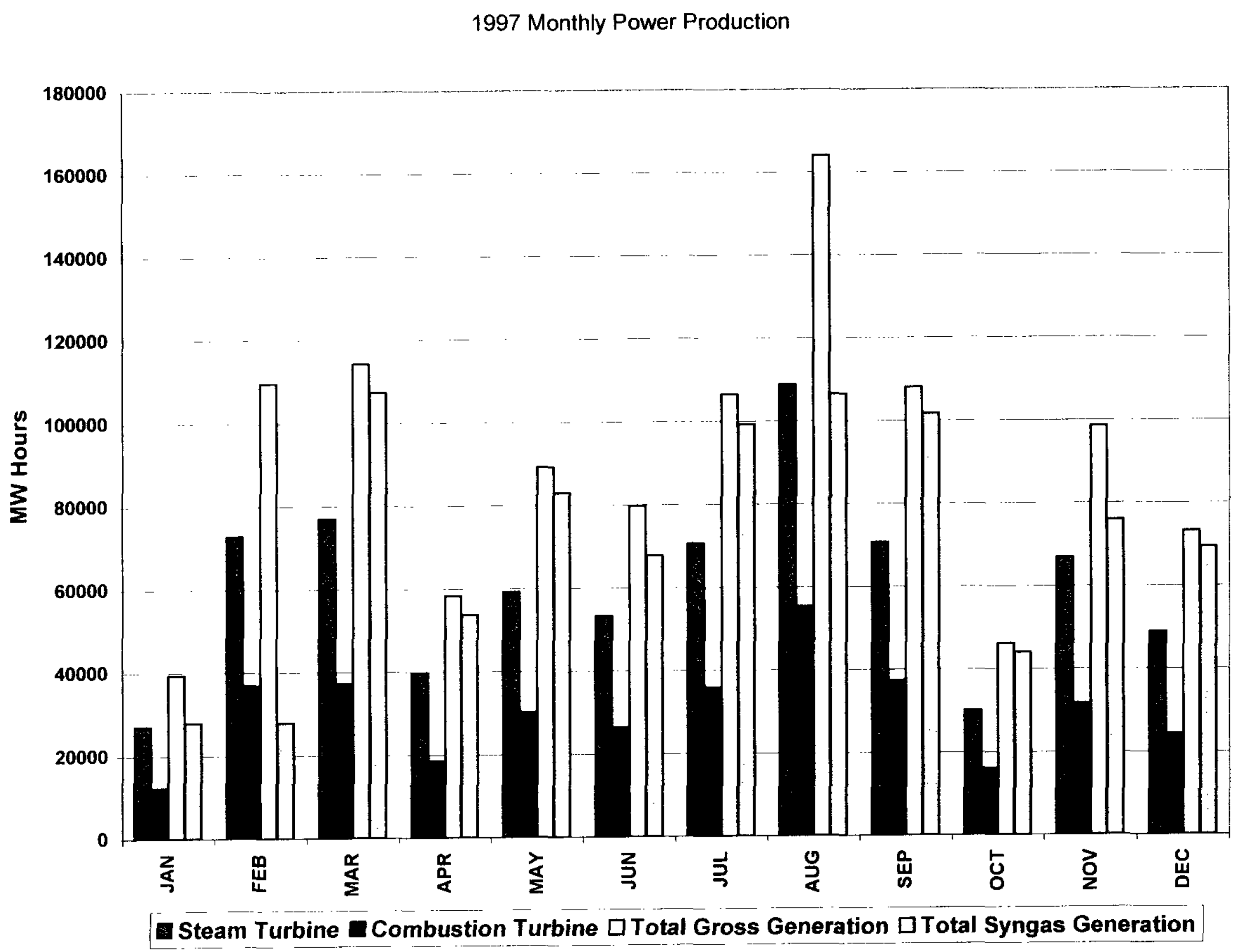


1997 DELIVERED SYNGAS
(MMBtu's)
MMBtu's
1000000
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Syngas Delivered (MMBtu's)

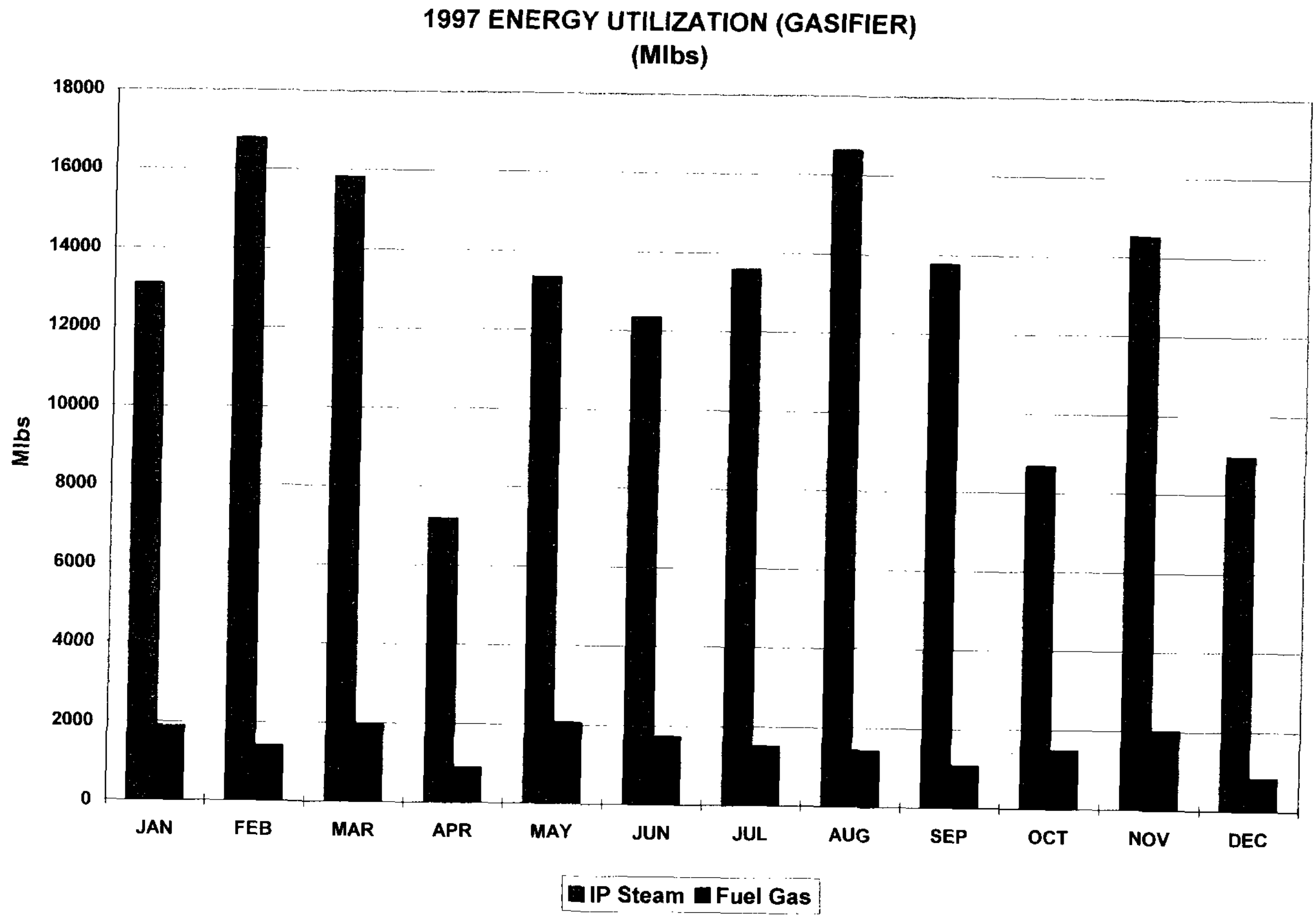
1997 DELIVERED #1600 LB STEAM
(Mlbs)



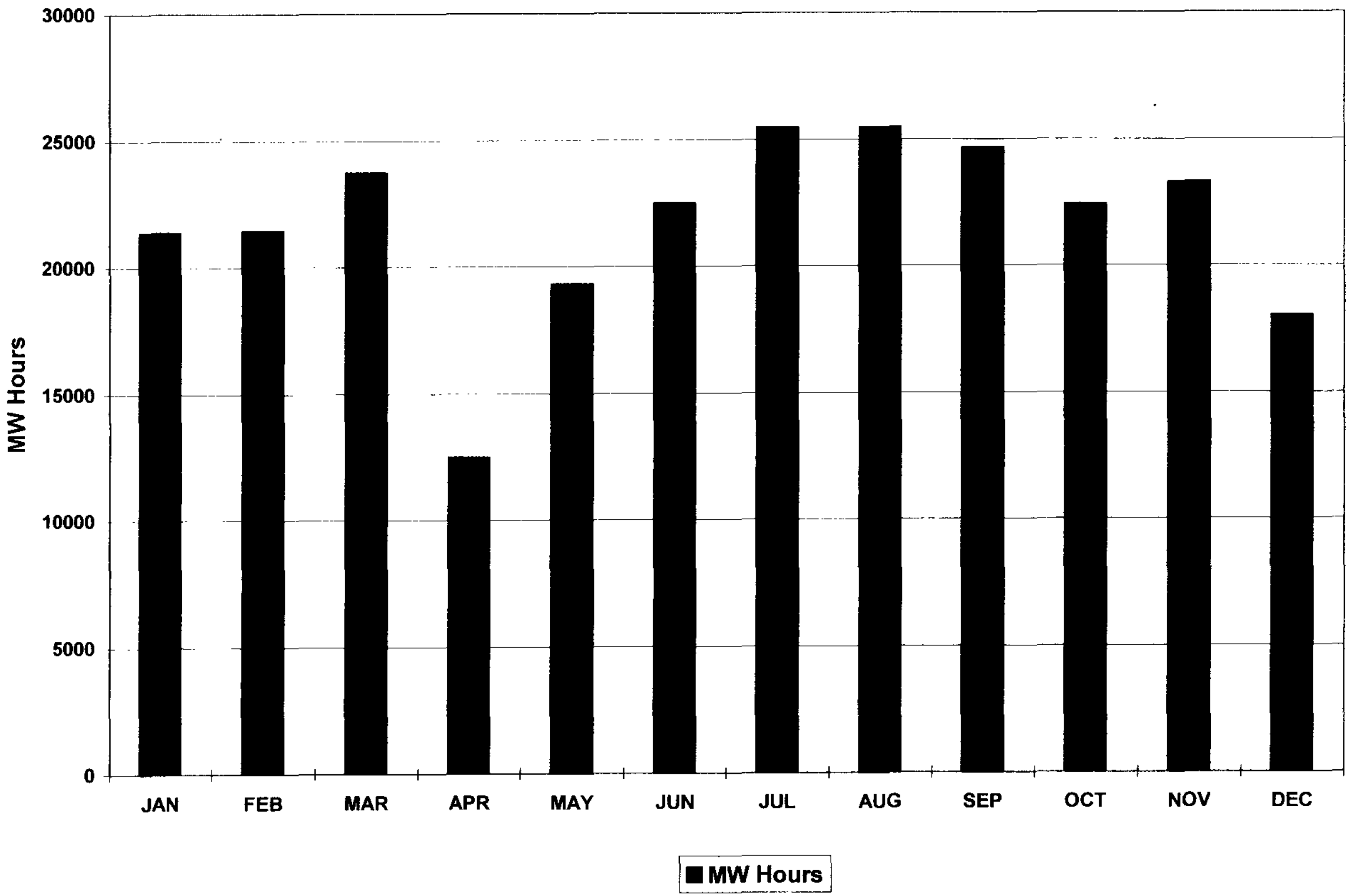

1997 FEED TO GASIFIER
(TONS)
Tons
70000
60000
50000
40000
30000
20000
10000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Coal Feed
Oxygen Feed



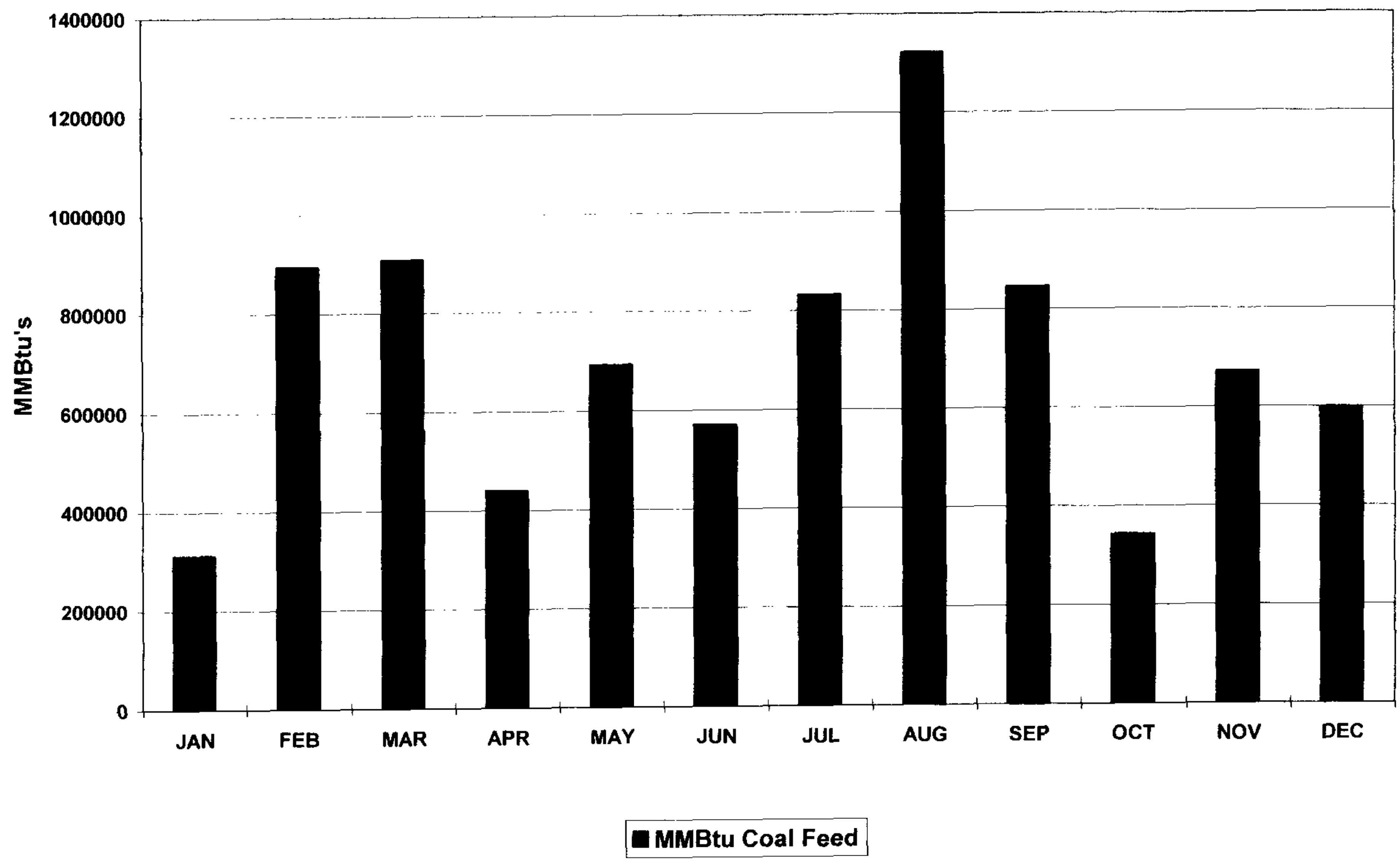
1997 Monthly Power Production
MW Hours
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Steam Turbine
Combustion Turbine
Total Gross Generation
Total Syngas Generation

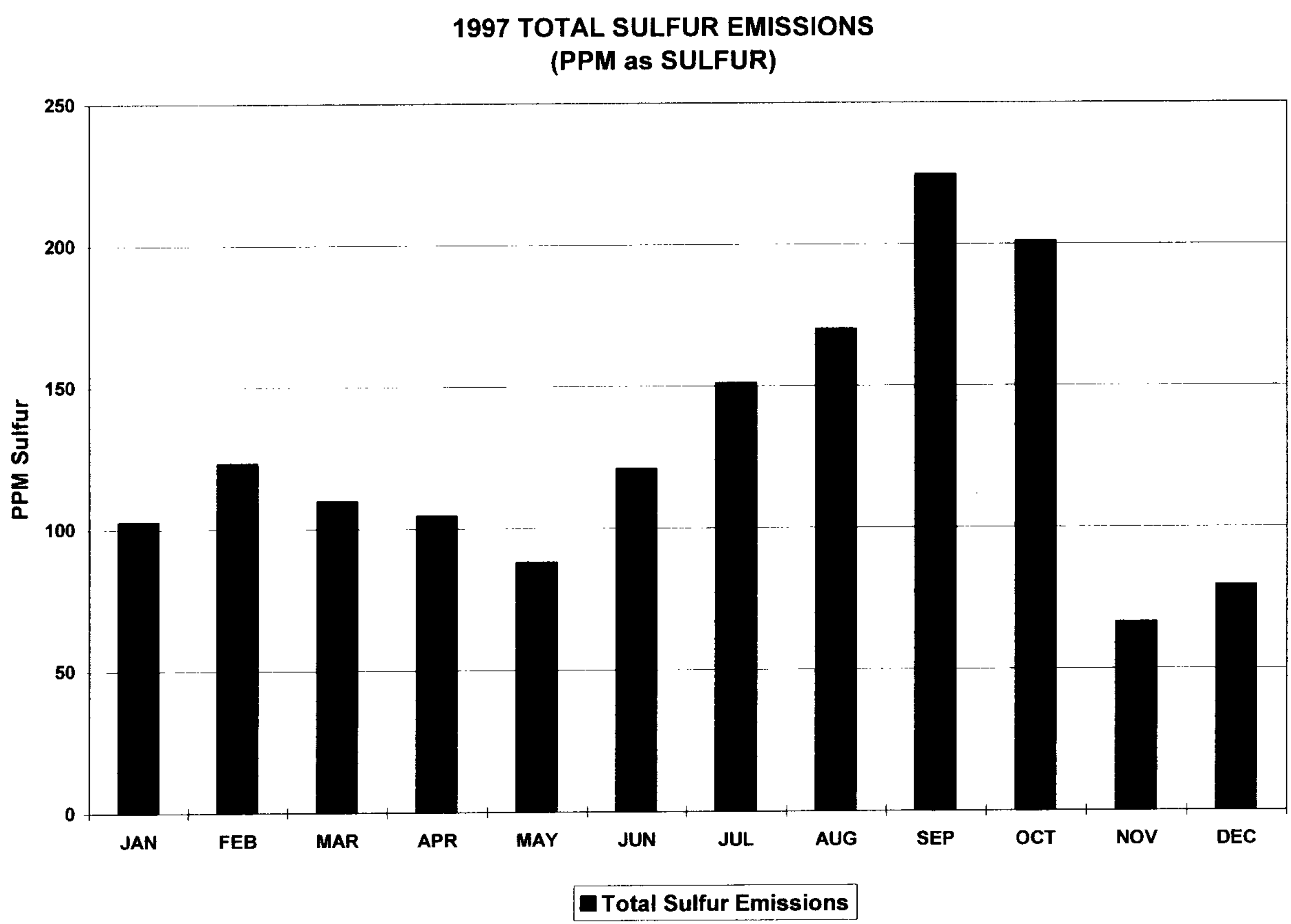

1997 ENERGY UTILIZATION (GASIFIER)
(Mlbs)
Mlbs
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
IP Steam
Fuel Gas

1997 ELECTRICAL ENERGY UTILIZATION GASIFICATION PLANT (MWH)

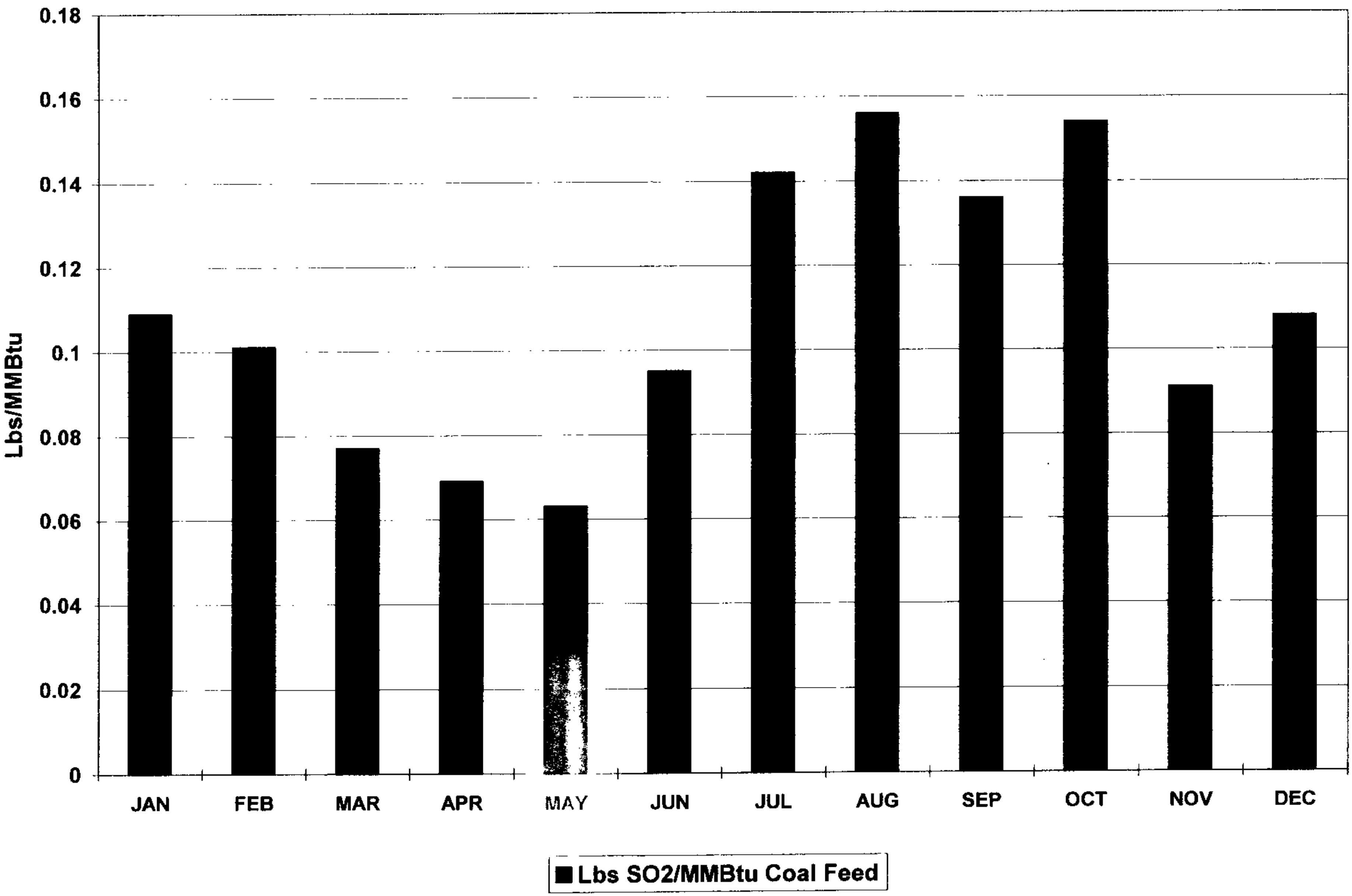


1997 COAL FEED TO GASIFIER (MMBtu's)




1997 TOTAL SULFUR EMISSIONS
(PPM as SULFUR)
PPM Sulfur
250
200
150
100
50
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Total Sulfur Emissions

1997 POUNDS OF SO2/MMBtu OF COAL FEED
(TOTAL REPOWERING EMISSIONS)



APPENDIX E

ENVIRONMENTAL TESTING

In May of 1997, GSI contracted with TRC Environmental Corporation to complete comprehensive environmental testing of both proprietary and non-proprietary streams within the Gasification facility. Included herein, is the results of that comprehensive analysis program for the following non-proprietary locations:

Tail Gas Incinerator Stack
Sweet Syngas Stream (Product Gas)
Equipment Leak Fugitive Emissions
Coal Slurry
Slag
Sulfur
Process Wastewater

Additionally you will find a copy of the Lab Report dealing with detailed analysis of the solids streams entitled "Solids Sampling Certificate of Analysis" which was also included in this comprehensive analysis.

ENVIRONMENTAL TESTING
1997

In May of 1997, GSI contracted with TRC Environmental Corporation to complete comprehensive testing of both proprietary and non-proprietary streams within the Gasification facility. The purpose of this testing was to prove the environmental integrity of the gasification process and to facilitate continued ways to improve upon the environmental performance.

During this testing period, the plant was operating at maximum capacity based on combustion turbine and steam turbine demand. Hawthorne coal was being utilized as the primary feedstock and no other unusual activities or trials were underway during this testing period. The values for all the parameters tested should indicate maximum concentrations under normal operating conditions. Tail gas recirculation rate and AGR/SRU performance are the only variables that would have an effect on the emissions as indicated. During this testing period, the AGR and SRU were operating within the normal guidelines of the manufacturer and the tail gas recirculation rate was operating within its normal flow. Other information that may have affected the results of this comprehensive testing are indicated within the body of the 1997 annual report or contained within the Appendices. It should be noted however, that every effort was made during this testing period to maintain a stable, consistent operation of the gasification process and to maintain the combustion turbine and steam turbine at peak load. Results of this testing were used to confirm our initial air permit application and must meet the demands of the EPA for quality of analysis and operational statistical recovery.

Table 2-5

Emissions Summary
Site Location 7 - Tail Gas Incinerater Stack

DATE TEST NUMBER		05/20/97 1	05/21/97 2	05/22/97 3	Average
Stack Gas Properties[1]					
Stack Temperature	°F	488	476	466	476
Moisture	%	13.5	11.0	10.7	11.7
Volumetric Flow Rate, Actual	acfm[2]	14760	13927	13631	14106
Volumetric Flow Rate, Dry Std.	dscfm[3]	7021	6943	6896	6953
Volumetric Flow Rate, Dry Std.	dscm/hr	11930	11798	11718	11816
Emissions Concentration					
Antimony	mg/dscm	<0.092	<9.12E-03	<9.32E-03	<9.22E-03
Arsenic	mg/dscm	<0.092	0.020	0.008	0.014
Cadmium	mg/dscm	<4.59E-03	<4.56E-04	<4.66E-04	<4.61E-04
Chromium	mg/dscm	<9.18E-03	7.62E-03	9.54E-03	8.58E-03
Cobalt	mg/dscm	<9.18E-03	<9.12E-04	1.51E-03	<1.21E-03
Manganese[5]	mg/dscm	48.8	0.050	0.022	0.036
Mercury	mg/dscm	4.61E-03	2.95E-03	4.54E-03	3.75E-03
Nickel	mg/dscm	<0.018	2.96E-03	4.44E-03	3.70E-03
Selenium	mg/dscm	<0.092	<9.12E-03	<9.32E-03	<9.22E-03
Particulate Matter (total)	grains/dscf	0.030	0.042	0.007	0.026
Particulate Matter (PM10)	grains/dscf	0.006	0.005	0.003	0.005
Sulfuric Acid	mg/dscm	93.0	no data[4]	59.0	76.0
Hydrogen Sulfide	ppmv	<0.040	<0.040	<0.040	<0.040
Benzene	ppmv	<0.047	<0.048	0.250	<0.115
Toluene	ppmv	0.056	<0.048	<0.047	<0.050
Ethyl Benzene	ppmv	0.150	<0.048	0.082	<0.093
Total Xylenes	ppmv	<0.047	<0.048	<0.047	<0.047
Ammonia	mg/dscm	29.2	<3.51	<2.71	<11.8
Cyanide	mg/dscm	<0.158	<0.134	<0.115	<0.136
Phenol	mg/dscm	<0.442	<0.445	<0.441	<0.443
Hydrogen	ppmv	<190	<190	<190	<190
Methane	ppmv	<20.0	<20.0	<20.0	<20.0
Carbon Dioxide	%-dry	19.5	15.6	13.3	16.1
Oxygen	%-dry	10.1	10.4	11.7	10.7
Carbon Monoxide	ppm	<1.00	<1.00	<1.00	<1.00
Sulfur Dioxide	ppm	1463	713	732	970
Nitrogen Oxides	ppm	187	178	167	177

Table 2-5

Emissions Summary
Site Location 7 - Tail Gas Incinerater Stack
(Continued)

DATE TEST NUMBER		05/20/97 1	05/21/97 2	05/22/97 3	Average
Mass Emission Rate					
Antimony	lbs/hr	<2.41E-03	<2.37E-04	<2.41E-04	<2.39E-04
Arsenic	lbs/hr	<2.41E-03	5.08E-04	2.07E-04	3.58E-04
Cadmium	lbs/hr	<1.21E-04	<1.19E-05	<1.20E-05	<1.19E-05
Chromium	lbs/hr	<2.41E-04	1.98E-04	2.47E-04	2.22E-04
Cobalt	lbs/hr	<2.41E-04	<2.37E-05	3.90E-05	<3.14E-05
Manganese[5]	lbs/hr	1.28	1.29E-03	5.69E-04	9.30E-04
Mercury	lbs/hr	1.21E-04	7.68E-05	1.17E-04	9.71E-05
Nickel	lbs/hr	<4.83E-04	7.70E-05	1.15E-04	9.58E-05
Selenium	lbs/hr	<2.41E-03	<2.37E-04	<2.41E-04	<2.39E-04
Particulate Matter (total)	lbs/hr	1.79	2.36	0.42	1.52
Particulate Matter (PM10)	lbs/hr	0.37	0.27	0.19	0.28
Sulfuric Acid	lbs/hr	2.43	no data[4]	1.52	1.98
Hydrogen Sulfide	lbs/hr	<1.49E-03	<1.47E-03	<1.46E-03	<1.47E-03
Benzene	lbs/hr	<4.01E-03	<4.05E-03	<0.021	<1.25E-02
Toluene	lbs/hr	5.63E-03	<4.78E-03	<4.64E-03	<4.71E-03
Ethyl Benzene	lbs/hr	0.017	<5.51E-03	9.34E-03	<7.42E-03
Total Xylenes	lbs/hr	<4.01E-03	<4.05E-03	<3.94E-03	<4.00E-03
Ammonia	lbs/hr	0.767	<0.091	<0.070	<0.081
Cyanide	lbs/hr	<0.004	<0.003	<0.003	<0.003
Phenol	lbs/hr	<0.012	<0.012	<0.011	<0.011
Hydrogen	lbs/hr	<0.419	<0.415	<0.412	<0.413
Methane	lbs/hr	<0.372	<0.368	<0.365	<0.367
Carbon Monoxide	lbs/hr	<0.031	<0.030	<0.030	<0.030
Sulfur Dioxide	lbs/hr	102	49.5	50.4	67.4
Nitrogen Oxides	lbs/hr	9.38	8.84	8.25	8.82

1 - Stack gas properties were taken from Method 29 testing.
2 - acfm = actual cubic feet per minute.
3 - dscfm = dry standard cubic feet per minute at 68°F and 29.92 in. Hg.
4 - Sample was accidentally broken at the laboratory.
5 - $KMnO_4$ contaminated HNO_3/H_2O_2 in sample 1 with manganese due to sampling train backflush. Sample 1 data was not included in average.

Table 2-6

Process Gas Analysis Summary
Site Location 8 - Sweet Syngas

DATE SAMPLE NUMBER TIME		05/20/97 1 17:55-18:59	05/21/97 2 10:35-11:35	05/22/97 3 07:30-08:30	Average
Process Gas Properties					
Temperature	°F	417	418	429	421
Moisture	%	1.21	1.74	2.44	1.80
Volumetric Flow Rate, Dry Std.	dscfm[1]	7405	7500	7526	7477
Volumetric Flow Rate, Dry Std.	dscm/hr	12583	12744	12788	12705
CO_2	%-dry	17.0	17.0	17.0	17.0
O_2	%-dry	<1.00	<1.00	<1.00	<1.00
Hydrogen Sulfide					
Concentration	ppm	88.4	41.6	36.0	55.3
Process Flow rate	lbs/hr	3.48	1.66	1.44	2.19

1 - dscfm = dry standard cubic feet per minute at 68°F and 29.92 in. Hg. Data provided by Destec.

Table 2-7

Plant Air Sampling Summary
Site Location 16 - Equipment Leaks

SAMPLE LOCATION DATE		2 5/20/97	3 5/21/97	5 5/22/97	AVERAGE
METHODS 3A AND 10					
Time		16:40-17:00	10:30-11:30	07:30-08:30	
Carbon Dioxide Concentration	ppm	<1.00	<1.00	<1.00	<1.00
Carbon Monoxide Concentration	ppm	<1.00	<1.00	4.30	<2.10
METHOD TO-14					
Time		16:40-17:45	10:30-11:30	07:30-08:30	
Hydrogen					
Concentration	%	<0.019	<0.020	<0.018	<0.019
Concentration	ppmv	<190	<200	<180	<190
Methane					
Concentration	%	<0.002	<0.002	<0.002	<0.002
Concentration	ppmv	<20.0	<20.0	<20.0	<20.0
Benzene					
Concentration	ppmv	<0.047	<0.005	<0.005	<0.019
Toluene					
Concentration	ppmv	<0.047	<0.005	0.005	<0.019
METHOD 18					
Time		16:40-17:00	10:30-11:30	07:30-08:30	
Hydrogen Sulfide					
Concentration	ppmv	<0.040	<0.040	0.047	<0.042
METHOD 18 (NIOSH 1501)					
Time		16:40-18:40	10:30-12:30	07:30-09:30	
Naphthalene					
Concentration	μg/liter	<0.083	<0 083	<0.083	<0.083
Concentration	ppmv	<0.016	<0.016	<0.016	<0.016

Table 2-8

Plant Air Sampling Summary
Site Location 17 - Slurry Preparation

DATE SAMPLE NUMBER TIME	5/20/97 1 12:00-20:00	 12:00-20:00	5/21/97 2 07:35-14:40	 07:35-14:40	5/22/97 3 06:29-12:40	 06:35-12:40
Sample Location	2nd floor	3rd floor	2nd floor	3rd floor	2nd floor	3rd floor
Particulate						
Concentration $\mu g/m^3$	39.9	77.6	67.2	224	62.6	99.1
PM_{10}						
Concentration $\mu g/m^3$	22.9	70.0	72.5	165	86.3	107

Table 2-9

Coal Slurry Analysis Summary
Site Location 1

SAMPLE NUMBER DATE		1 5/20/97	2 5/21/97	3 5/22/97	AVERAGE
<u>Group I Metals</u>					
Antimony	mg/kg	<10.00	<10.00	<10.00	<10.00
Arsenic	mg/kg	<10.00	<10.00	<10.00	<10.00
Cadmium	mg/kg	<0.50	<0.50	<0.50	<0.50
Chromium	mg/kg	4.77	4.21	4.67	4.55
Cobalt	g/kg	1.78	1.54	1.69	1.67
Manganese	mg/kg	13.6	10.8	11.8	12.07
Mercury	mg/kg	<0.08	<0.08	<0.08	<0.080
Nickel	mg/kg	5.5	4.18	5.22	4.97
Selenium	mg/kg	<10.00	<10.00	<10.00	<10.00
<u>Group II Metals</u>					
Aluminum	mg/kg	361	271	338	323.33
Barium	mg/kg	6.93	4.88	7.2	6.34
Beryllium	mg/kg	1.3	0.976	1.27	1.18
Boron	mg/kg	104	81.6	112	99.20
Calcium	mg/kg	2250	1480	1630	1787
Copper	mg/kg	3.74	2.89	3.15	3.26
Iron	mg/kg	6840	5350	5290	5827
Lead	mg/kg	<5.00	<5.00	<5.00	<5.00
Magnesium	mg/kg	342	236	288	289
Molybdenum	mg/kg	<1.0	<1.0	<1.0	<1.0
Phosphorous	mg/L P	28.00	21.80	6.20	18.67
Potassium	mg/kg	129	99.8	124	118
Silicon	mg/kg	155	133	169	152
Silver	mg/kg	<1.0	<1.0	<1.0	<1.0
Sodium	mg/kg	528	351	304	394
Thallium	mg/kg	<20.0	<20.0	<20.0	<20.0
Vanadium	mg/kg	10.30	8.67	9.75	9.57
Zinc	mg/kg	26.50	27.90	25.70	26.70
<u>Ultimate Analysis</u>					
Carbon	%	69.68	69.33	67.98	69.00
Hydrogen	%	4.79	4.72	4.66	4.72
Nitrogen	%	1.53	1.40	1.44	1.46
Oxygen	%	12.03	13.35	13.33	12.90
Sulfur	%	0.26	0.17	0.44	0.29
Ash	%	11.66	10.97	12.05	11.56
TCLP (total)	mg/L	<0.342	<1.01	<0.787	<0.713

Table 2-10

Sour Water Analysis Summary
Site Location 4

SAMPLE NUMBER DATE		1 5/20/97	2 5/21/97	3 5/22/97	AVERAGE
pH		9.05	8.35	8.34	8.58
Ammonia	mg/L N	865	1710	1880	1485
Cyanide	mg/L	3.12	2.16	3.73	3.00
Sulfides	mg/L	7.62	8.62	9.62	8.62

Table 2-11

Slag Analysis Summary
Site Location 10

SAMPLE NUMBER DATE		1 5/20/97	2 5/21/97	3 5/22/97	AVERAGE
Carbon Content	%	20.44	15.02	11.55	15.67
Moisture Content	%	41.28	30.5	18.73	30.17
Group I Metals					
Antimony	mg/kg	<10.0	<10.0	<10.0	<10.0
Arsenic	mg/kg	<10.0	<10.0	<10.0	<10.0
Cadmium	mg/kg	<0.50	<0.50	<0.50	<0.50
Chromium	mg/kg	29.1	35.2	24.5	29.60
Cobalt	mg/kg	4.73	5.69	5.62	5.35
Manganese	mg/kg	33.6	36.8	29.4	33.3
Mercury	mg/kg	<0.08	<0.08	<0.08	<0.08
Nickel	mg/kg	24.8	21.3	22.6	22.9
Selenium	mg/kg	<10.0	<10.0	<10.0	<10.0
Group II Metals					
Aluminum	mg/kg	7610	10400	7570	8527
Barium	mg/kg	34.4	45.1	34.1	37.9
Beryllium	mg/kg	1.78	2.5	1.81	2.03
Boron	mg/kg	106	157	122	128
Calcium	mg/kg	8810	10600	8350	9253
Copper	mg/kg	10.3	11.7	13.9	12.0
Iron	mg/kg	16300	18600	16900	17267
Lead	mg/kg	7.44	8.07	9.07	8.19
Magnesium	mg/kg	1320	1610	1220	1383
Molybdenum	mg/kg	5.09	2.04	2.78	3.30
Phosphorous	mg/L P	117	<0.020	<0.020	<39.0
Potassium	mg/kg	1580	2010	1470	1687
Silicon	mg/kg	1190	1490	941	1207
Silver	mg/kg	<1.0	<1.0	<1.0	<1.0
Sodium	mg/kg	779	905	546	743
Thallium	mg/L	<0.40	<0.40	<0.40	<0.40
Vanadium	mg/kg	21.90	30.40	23.00	25.10
Zinc	mg/kg	20.80	38.10	40.00	32.97
TCLP (total)	mg/L	<0.406	<0.735	<0.904	<0.682

Table 2-12

Sulfur Analysis Summary
Site Location 11

SAMPLE NUMBER DATE		1 5/20/97	2 5/21/97	3 5/22/97	AVERAGE
TCLP (total)	mg/L	0.904	0.111	0.158	0.391

Table 2-13

Process Wastewater Analysis Summary
Site Location 13

SAMPLE NUMBER DATE		1 5/20/97	2 5/21/97	3 5/22/97	AVERAGE
Priority Pollutant BNA's[1]	µg/L	<10.0	<10.0	<10.0	<10.00
pH		8.32	8.89	9.46	8.89
Acidity	mg/L $CaCO_3$	<10.0	<10.0	<10.0	<10.00
Alkalinity	mg/L $CaCO_3$	290	229	114	211
Conductivity	umhos/cm	4690	4070	1930	3563
Total Solids	mg/L	3450	2960	1450	2620
Total Suspended Solids	mg/L	<10.0	<10.0	<10.0	<10.0
Total Dissolved Solids	mg/L	3450	3030	1430	2637
BOD (5 day)	mg/L	169	<6.0	60.8	<78.60
COD	mg/L	323	255	91.2	223
Total Oxygen Demand	mg/L	492	261	152	302
TOC	mg/L	136	116	35.4	95.80
Total Inorganic Carbon	mg/L	109	110	32.3	83.77
Oil & Grease	mg/L	<5.0	<5.0	<5.0	<5.0
Ammonia-N	mg/L N	12.8	20.3	2.68	11.93
Cyanide	mg/L	12.7	8.1	3.33	8.04
Formate	µg/ml	1.68	1.11	27.92	10.24
Phenols	mg/L	<0.10	<0.10	<0.10	<0.10
Thiocyanate	µg/ml	11.89	7.63	2.79	7.44
Sulfides	mg/L	2.2	<1.50	<1.50	<1.73
Sulfites	mg/L	<4.0	<4.0	<4.0	<4.0
Sulfates	mg/L	1010	657	531	733
Chlorides	mg/L	770	730	262	587
Fluorides	mg/L	110	77.2	6.25	64.5
Nitrates	mg/L N	4.88	4.02	3.02	3.97
Nitrites	mg/L N	0.063	0.081	0.123	0.089
<u>Group I Metals</u>					
Antimony	mg/L	<0.100	<0.100	<0.100	<0.100
Arsenic	mg/L	0.563	0.343	0.121	0.342
Cadmium	mg/L	<0.005	<0.005	<0.005	<0.005
Chromium	mg/L	0.010	<0.010	<0.010	<0.010
Cobalt	mg/L	<0.010	<0.010	<0.010	<0.010
Manganese	mg/L	0.013	0.011	0.006	0.010
Mercury	mg/L	<0.0002	<0.0002	<0.0002	<0.0002
Nickel	mg/L	<0.02	<0.02	<0.02	<0.020
Selenium	mg/L	1.68	2.04	0.154	1.29

Table 2-13

Process Wastewater Analysis Summary
Site Location 13
(Continued)

SAMPLE NUMBER DATE		1 5/20/97	2 5/21/97	3 5/22/97	AVERAGE
Group II Metals					
Aluminum	mg/L	0.562	0.655	0.134	0.450
Barium	mg/L	0.027	0.023	0.035	0.028
Beryllium	mg/L	<0.002	<0.002	<0.002	<0.002
Boron	mg/L	29.7	43.2	3.04	25.31
Calcium	mg/L	80.9	71.7	116	90
Copper	mg/L	<0.020	<0.020	<0.020	<0.020
Iron	mg/L	5.51	3.22	1.44	3.39
Lead	mg/L	<0.050	<0.050	<0.050	<0.050
Magnesium	mg/L	17.5	21.2	37.4	25.4
Molybdenum	mg/L	0.014	0.013	0.018	0.015
Phosphorous	mg/L P	0.865	0.728	1.23	0.941
Potassium	mg/L	11.7	9.80	13.6	11.7
Silicon	mg/L	2.88	4.09	1.81	2.93
Silver	mg/L	<0.010	<0.010	<0.010	<0.010
Sodium	mg/L	989	861	259	703
Thallium	mg/L	<0.40	<0.40	<0.40	<0.40
Vanadium	mg/L	<0.010	<0.010	<0.010	<0.010
Zinc	mg/L	0.078	0.058	0.052	0.063

1 - All semivolatile target compounds were below the minimum quantitation limit of 10 µg/L. Several compounds were detected at levels below the quantitation limit and estimated concentrations for these compounds are provided in the laboratory report included in Appendix M.

ROSS Analytical Services, Inc.
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CERTIFICATE OF ANALYSIS

Client:

TRC Environmental Corp.
Ft of John St Boot Mills
Lowell, MA 01852

Attn: Ed MacKinnon

Work Order #: 97-05-181
Client Code: TRC_LOWELL
Report Date: 06/25/97
Work ID: Samples for mutliple tests
Date Received: 05/23/97

Purchase Order: 22428003000000/Destek

SAMPLE IDENTIFICATION

Lab Number	Sample Description	Lab Number	Sample Description
01	Coal Slurry DES-#1-COMP-1	02	Coal Slurry DES-#1-COMP-2
03	Coal Slurry DES-#1-COMP-3	04	Sour Water DES-#4-COMP-1
05	Sour Water DES-#4-COMP-2	06	Sour Water DES-#4-COMP-3
07	Slag DES-#10-Grab-1	08	Slag DES-#10-Grab-2
09	Slag DES-#10-Grab-3	10	Sulfur DES-#11-GRAB-1
11	Sulfur DES-#11-GRAB-2	12	Sulfur DES-#11-GRAB-3

Enclosed are the analytical results for the samples listed above. Analyses were performed by the methods referenced in the Test Methodologies section, while any special circumstances are described in the Report Comments section. Unless otherwise noted, sample results are not moisture-corrected. Most analytes are reported relative to an Estimated Quantitation Limit (EQL), which is the lowest concentration that can be reliably measured under routine laboratory conditions. Questions or comments concerning the enclosed results should be directed to your Client Services Representative.

Ultimate analysis was done at Galbraith Labs
Grain size was done at Solar Labs
Their reports are included

Certificate approved by
Carol L. Turner

TEST METHODOLOGIES

Ammonia was determined by distillation from alkali followed by manual titration as in EPA Method 350.2.

pH was determined in aqueous liquids electrometrically as in EPA 150.1 and 9040B. It was determined as soon as possible after sample receipt. Because the stated holding time for pH is "immediately [after collection]", this analysis was past its holding time.

Sulfide was determined by iodometric titration as in EPA Method 376.1 and 9030A.

Total cyanide was determined by distillation followed by manual colorimetry as in EPA Methods 335.2 and 9010A.

Total phosphorus was determined by acid persulfate digestion followed by manual colorimetry as in EPA Method 365.2.

The bottle leaching step of TCLP (for metals and semivolatile organics) was performed by EPA Method 1311. Matrix spikes, if any, were added at the time of digestion or extraction for further analyses.

The Zero Headspace Extraction (ZHE) leaching step of the TCLP (for volatile organics) was performed by EPA Method 1311. Bias adjustment spikes, if any, were added at the time of digestion or extraction for further analyses. Reported results are not bias adjusted.

TCLP target list organochlorine pesticides and PCB's were determined using gas chromatography with electron capture detection as in EPA Method 8080A.

TCLP target list phenoxy acid herbicides were determined by gas chromatography with electron capture detection as in EPA Method 8150B.

Metals were determined in aqueous samples and leachates by digestion with nitric and hydrochloric acids as in EPA Method 3010A, followed by Inductively Coupled Plasma Emission Spectroscopy as in EPA Method 6010A unless noted otherwise.

Mercury was determined in aqueous samples and leachates by cold vapor atomic absorption after acid/permanganate digestion as in EPA Methods 245.1 and 7470A. A single analysis was performed unless otherwise noted.

Metals were determined in solid and non-aqueous liquid samples by digestion with nitric acid, hydrogen peroxide, and hydrochloric acid as in EPA Method 3050A, followed by Inductively Coupled Plasma Emission Spectroscopy as in EPA Method 6010A, unless noted otherwise.

Mercury was determined in solid and non-aqueous liquid samples by cold vapor atomic absorption after acid/permanganate digestion as in EPA Methods 245.5 and 7471A. A single analysis was performed unless otherwise noted.

TCLP target list volatile organics were determined by gas chromatography/mass spectrometry as in EPA Method 8240B, using a capillary column.

TCLP target list semivolatile organics (base/neutral/acid) were determined by gas chromatography/mass spectrometry as in EPA Method 8270B.

Aqueous samples and leachates were extracted for semivolatile organics in a continuous extractor using methylene chloride as in EPA Method 3520B.

Aqueous samples and leachates were extracted for organochlorine pesticides and PCB's in a continuous extractor using methylene chloride as in EPA Method 3520B.

Aqueous samples were extracted for phenoxy acid herbicides in a separatory funnel with diethyl ether and derivatized with diazomethane as in EPA Method 8150B.

<u>Sample Description:</u> Coal Slurry DES-#1-COMP-1 <u>Lab No.:</u> 01

Analyte Description	Result	Units	EQL
Aluminum by ICP	361	mg/Kg	10
Antimony by ICP	<EQL	mg/Kg	10
Arsenic by ICP	<EQL	mg/Kg	10
Barium by ICP	6.93	mg/Kg	0.40
Beryllium by ICP	1.30	mg/Kg	0.20
Cadmium by ICP	<EQL	mg/Kg	0.50
Calcium by ICP	2250	mg/Kg	20
Chromium by ICP	4.77	mg/Kg	1.0
Cobalt by ICP	1.78	g/Kg	1.0
Copper by ICP	3.74	mg/Kg	2.0
Iron by ICP	6840	mg/Kg	10
Lead by ICP	<EQL	mg/Kg	5.0
Magnesium by ICP	342	mg/Kg	10
Manganese by ICP	13.6	mg/Kg	0.50
Molybdenum by ICP	<EQL	mg/Kg	1.0
Nickel by ICP	5.5	mg/Kg	2.0
Potassium by ICP	129	mg/Kg	20
Selenium by ICP	<EQL	mg/Kg	10
Silicon by ICP	155	mg/Kg	50
Silver by ICP	<EQL	mg/Kg	1.0
Sodium by ICP	528	mg/Kg	50
Thallium by ICP	<EQL	mg/Kg	20
Vanadium by ICP	10.3	mg/Kg	1.0
Zinc by ICP	26.5	mg/Kg	2.0
Boron by ICP	104	mg/Kg	5.0
Mercury by CVAA	<EQL	mg/Kg	0.08
Total P by EPA 365.2	28.0	mg/L P	0.020

<u>Sample Description:</u> Coal Slurry DES-#1-COMP-2 <u>Lab No.:</u> 02

Analyte Description	Result	Units	EQL
Aluminum by ICP	271	mg/Kg	10
Antimony by ICP	<EQL	mg/Kg	10
Arsenic by ICP	<EQL	mg/Kg	10
Barium by ICP	4.88	mg/Kg	0.40
Beryllium by ICP	0.976	mg/Kg	0.20
Cadmium by ICP	<EQL	mg/Kg	0.50
Calcium by ICP	1480	mg/Kg	20
Chromium by ICP	4.21	mg/Kg	1.0
Cobalt by ICP	1.54	mg/Kg	1.0
Copper by ICP	2.89	mg/Kg	2.0
Iron by ICP	5350	mg/Kg	10
Lead by ICP	<EQL	mg/Kg	5.0
Magnesium by ICP	236	mg/Kg	10
Manganese by ICP	10.8	mg/Kg	0.50

Analyte Description	Result	Units	EQL
Molybdenum by ICP	<EQL	mg/Kg	1.0
Nickel by ICP	4.18	mg/Kg	2.0
Potassium by ICP	99.8	mg/Kg	20
Selenium by ICP	<EQL	mg/Kg	10
Silicon by ICP	133	mg/Kg	50
Silver by ICP	<EQL	mg/Kg	1.0
Sodium by ICP	351	mg/Kg	50
Thallium by ICP	<EQL	mg/Kg	20
Vanadium by ICP	8.67	mg/Kg	1.0
Zinc by ICP	27.9	mg/Kg	2.0
Boron by ICP	81.6	mg/Kg	5.0
Mercury by CVAA	<EQL	mg/Kg	0.08
Total P by EPA 365.2	21.8	mg/L P	0.020

Sample Description: Coal Slurry DES-#1-COMP-3 Lab No.: 03

Analyte Description	Result	Units	EQL
Aluminum by ICP	338	mg/Kg	10
Antimony by ICP	<EQL	mg/Kg	10
Arsenic by ICP	<EQL	mg/Kg	10
Barium by ICP	7.2	mg/Kg	0.40
Beryllium by ICP	1.27	mg/Kg	0.20
Cadmium by ICP	<EQL	mg/Kg	0.50
Calcium by ICP	1630	mg/Kg	20
Chromium by ICP	4.67	mg/Kg	1.0
Cobalt by ICP	1.69	mg/Kg	1.0
Copper by ICP	3.15	mg/Kg	2.0
Iron by ICP	5290	mg/Kg	10
Lead by ICP	<EQL	mg/Kg	5.0
Magnesium by ICP	288	mg/Kg	10
Manganese by ICP	11.8	mg/Kg	0.50
Molybdenum by ICP	<EQL	mg/Kg	1.0
Nickel by ICP	5.22	mg/Kg	2.0
Potassium by ICP	124	mg/Kg	20
Selenium by ICP	<EQL	mg/Kg	10
Silicon by ICP	169	mg/Kg	50
Silver by ICP	<EQL	mg/Kg	1.0
Sodium by ICP	304	mg/Kg	50
Thallium by ICP	<EQL	mg/Kg	20
Vanadium by ICP	9.75	mg/Kg	1.0
Zinc by ICP	25.7	mg/Kg	2.0
Boron by ICP	112	mg/Kg	5.0
Mercury by CVAA	<EQL	mg/Kg	0.08
Total P by EPA 365.2	6.20	mg/L P	0.020

Sample Description: Sour Water DES-#4-COMP-1 **Lab No.:** 04

Analyte Description	Result	Units	EQL
Ammonia by EPA 350.2	865	mg/L N	1.5
Total_CN by EPA 335.2/9010	3.12	mg/L	0.010
Sulfide by 376.1/9030A	7.62	mg/L	1.5

Sample Description: Sour Water DES-#4-COMP-2 **Lab No.:** 05

Analyte Description	Result	Units	EQL
pH by EPA 150.1/9040B	8.35	Standard units	
Ammonia by EPA 350.2	1710	mg/L N	1.5
Total_CN by EPA 335.2/9010	2.16	mg/L	0.010
Sulfide by 376.1/9030A	8.62	mg/L	1.5

Sample Description: Sour Water DES-#4-COMP-3 **Lab No.:** 06

Analyte Description	Result	Units	EQL
pH by EPA 150.1/9040B	8.34	Standard units	
Ammonia by EPA 350.2	1880	mg/L N	1.5
Total_CN by EPA 335.2/9010	3.73	mg/L	0.010
Sulfide by 376.1/9030A	9.62	mg/L	1.5

Sample Description: Slag DES-#10-Grab-1 **Lab No.:** 07

Analyte Description	Result	Units	EQL
Total P by EPA 365.2	117	mg/L P	0.020
Thallium by ICP	<EQL	mg/L	0.40
Aluminum by ICP	7610	mg/Kg	10
Antimony by ICP	<EQL	mg/Kg	10
Arsenic by ICP	<EQL	mg/Kg	10
Barium by ICP	34.4	mg/Kg	0.40
Beryllium by ICP	1.78	mg/Kg	0.20
Cadmium by ICP	<EQL	mg/Kg	0.50
Calcium by ICP	8810	mg/Kg	20
Chromium by ICP	29.1	mg/Kg	1.0
Cobalt by ICP	4.73	mg/Kg	1.0
Copper by ICP	10.3	mg/Kg	2.0
Iron by ICP	16,300	mg/Kg	10
Lead by ICP	7.44	mg/Kg	5.0
Magnesium by ICP	1320	mg/Kg	10
Manganese by ICP	33.6	mg/Kg	0.50
Molybdenum by ICP	5.09	mg/Kg	1.0
Nickel by ICP	24.8	mg/Kg	2.0

Analyte Description	Result	Units	EQL
Potassium by ICP	1580	mg/Kg	20
Selenium by ICP	<EQL	mg/Kg	10
Silicon by ICP	1190	mg/Kg	50
Silver by ICP	<EQL	mg/Kg	1.0
Sodium by ICP	779	mg/Kg	50
Vanadium by ICP	21.9	mg/Kg	1.0
Zinc by ICP	20.8	mg/Kg	2.0
Boron by ICP	106	mg/Kg	5.0
Mercury by CVAA	<EQL	mg/Kg	0.08

Sample Description: Slag DES-#10-Grab-2 Lab No.: 08

Analyte Description	Result	Units	EQL
Total P by EPA 365.2	<EQL	mg/L P	0.020
Thallium by ICP	<EQL	mg/L	0.40
Aluminum by ICP	10,400	mg/Kg	10
Antimony by ICP	<EQL	mg/Kg	10
Arsenic by ICP	<EQL	mg/Kg	10
Barium by ICP	45.1	mg/Kg	0.40
Beryllium by ICP	2.5	mg/Kg	0.20
Cadmium by ICP	<EQL	mg/Kg	0.50
Calcium by ICP	10,600	mg/Kg	20
Chromium by ICP	35.2	mg/Kg	1.0
Cobalt by ICP	5.69	mg/Kg	1.0
Copper by ICP	11.7	mg/Kg	2.0
Iron by ICP	18,600	mg/Kg	10
Lead by ICP	8.07	mg/Kg	5.0
Magnesium by ICP	1610	mg/Kg	10
Manganese by ICP	36.8	mg/Kg	0.50
Molybdenum by ICP	2.04	mg/Kg	1.0
Nickel by ICP	21.3	mg/Kg	2.0
Potassium by ICP	2010	mg/Kg	20
Selenium by ICP	<EQL	mg/Kg	10
Silicon by ICP	1490	mg/Kg	50
Silver by ICP	<EQL	mg/Kg	1.0
Sodium by ICP	905	mg/Kg	50
Vanadium by ICP	30.4	mg/Kg	1.0
Zinc by ICP	38.1	mg/Kg	2.0
Boron by ICP	157	mg/Kg	5.0
Mercury by CVAA	<EQL	mg/Kg	0.08

Sample Description: Slag DES-#10-Grab-3 Lab No.: 09

Analyte Description	Result	Units	EQL
Total P by EPA 365.2	<EQL	mg/L P	0.020
Thallium by ICP	<EQL	mg/L	0.40
Aluminum by ICP	7570	mg/Kg	10
Antimony by ICP	<EQL	mg/Kg	10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Analyte Description	Result	Units	EQL
Arsenic by ICP	<EQL	mg/Kg	10
Barium by ICP	34.1	mg/Kg	0.40
Beryllium by ICP	1.81	mg/Kg	0.20
Cadmium by ICP	<EQL	mg/Kg	0.50
Calcium by ICP	8350	mg/Kg	20
Chromium by ICP	24.5	mg/Kg	1.0
Cobalt by ICP	5.62	mg/Kg	1.0
Copper by ICP	13.9	mg/Kg	2.0
Iron by ICP	16,900	mg/Kg	10
Lead by ICP	9.07	mg/Kg	5.0
Magnesium by ICP	1220	mg/Kg	10
Manganese by ICP	29.4	mg/Kg	0.50
Molybdenum by ICP	2.78	mg/Kg	1.0
Nickel by ICP	22.6	mg/Kg	2.0
Potassium by ICP	1470	mg/Kg	20
Selenium by ICP	<EQL	mg/Kg	10
Silicon by ICP	941	mg/Kg	50
Silver by ICP	<EQL	mg/Kg	1.0
Sodium by ICP	546	mg/Kg	50
Vanadium by ICP	23.0	mg/Kg	1.0
Zinc by ICP	40.0	mg/Kg	2.0
Boron by ICP	122	mg/Kg	5.0
Mercury by CVAA	<EQL	mg/Kg	0.08

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-1 Lab No. 01
Test Description TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL		0.50
7440-39-3	Barium	0.342		0.020
7440-43-9	Cadmium	<EQL		0.025
7440-47-3	Chromium	<EQL		0.050
7439-92-1	Lead	<EQL		0.25
7439-97-6	Mercury	<EQL		0.0020
7782-49-2	Selenium	<EQL		0.50
7440-22-4	Silver	<EQL		0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

7440-50-8	Copper	NA		0.10
7440-02-0	Nickel	NA		0.10
7440-66-6	Zinc	NA		0.10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-1 Lab No. 01
Test Description TCLP list pesticides Test Code 8080TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE RUN 06/05/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
57-74-9	Chlordane	<EQL		0.013
72-20-8	Endrin	<EQL		0.0005
76-44-8	Heptachlor and its epoxide	<EQL		0.0003
58-89-9	Lindane	<EQL		0.0003
72-43-5	Methoxychlor	<EQL		0.0024
8001-35-2	Toxaphene	<EQL		0.013

SURROGATE	%RECOVERY	LIMITS
Tetrachloro-m-xylene	86	40 - 160
Decachlorobiphenyl	100	40 - 150

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-1 Lab No. 01
Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL	____	0.010
93-72-1	2,4,5-TP (Silvex)	<EQL	____	0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	101	80 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-1 Lab No. 01
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	69	45 - 110
2-Fluorobiphenyl	65	30 - 110
Terphenyl-d14	71	40 - 125
Phenol-d5	68	30 - 110
2-Fluorophenol	67	5 - 125
2,4,6-Tribromophenol	103	45 - 130

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-1 Lab No. 01
Test Description TCLP list volatiles Test Code 8240TC

ZHE BEGUN 05/29/97 DATE ANALYZED 06/02/97 DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
71-43-2	Benzene	<EQL		0.025
56-23-5	Carbon tetrachloride	<EQL		0.025
108-90-7	Chlorobenzene	<EQL		0.025
67-66-3	Chloroform	<EQL		0.025
107-06-2	1,2-Dichloroethane	<EQL		0.025
75-35-4	1,1-Dichloroethylene	<EQL		0.025
78-93-3	Methyl ethyl ketone	<EQL		0.050
127-15-4	Tetrachloroethylene	<EQL		0.025
79-01-6	Trichloroethylene	<EQL		0.025
75-01-4	Vinyl chloride	<EQL		0.050

SURROGATE	%RECOVERY	LIMITS
1,2-Dichloroethane-d4	103	80 - 130
Toluene-d8	106	88 - 110
4-Bromofluorobenzene	100	85 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-2 Lab No. 02
Test Description TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL		0.50
7440-39-3	Barium	1.01		0.020
7440-43-9	Cadmium	<EQL		0.025
7440-47-3	Chromium	<EQL		0.050
7439-92-1	Lead	<EQL		0.25
7439-97-6	Mercury	<EQL		0.0020
7782-49-2	Selenium	<EQL		0.50
7440-22-4	Silver	<EQL		0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-50-8	Copper	NA		0.10
7440-02-0	Nickel	NA		0.10
7440-66-6	Zinc	NA		0.10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-2 Lab No. 02
Test Description TCLP list pesticides Test Code 8080TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE RUN 06/05/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
57-74-9	Chlordane	<EQL		0.013
72-20-8	Endrin	<EQL		0.0005
76-44-8	Heptachlor and its epoxide	<EQL		0.0003
58-89-9	Lindane	<EQL		0.0003
72-43-5	Methoxychlor	<EQL		0.0024
8001-35-2	Toxaphene	<EQL		0.013

SURROGATE	%RECOVERY	LIMITS
Tetrachloro-m-xylene	100	40 - 160
Decachlorobiphenyl	63	40 - 150

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-2 Lab No. 02
Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL		0.010
93-72-1	2,4,5-TP (Silvex)	<EQL		0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	101	80 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-2 Lab No. 02
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	77	45 - 110
2-Fluorobiphenyl	74	30 - 110
Terphenyl-d14	75	40 - 125
Phenol-d5	79	30 - 112
2-Fluorophenol	79	5 - 125
2,4,6-Tribromophenol	102	45 - 130

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-2 Lab No. 02
Test Description TCLP list volatiles Test Code 8240TC

ZHE BEGUN 05/29/97 DATE ANALYZED 06/02/97 DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
71-43-2	Benzene	<EQL		0.025
56-23-5	Carbon tetrachloride	<EQL		0.025
108-90-7	Chlorobenzene	<EQL		0.025
67-66-3	Chloroform	<EQL		0.025
107-06-2	1,2-Dichloroethane	<EQL		0.025
75-35-4	1,1-Dichloroethylene	<EQL		0.025
78-93-3	Methyl ethyl ketone	<EQL		0.050
127-18-4	Tetrachloroethylene	<EQL		0.025
79-01-6	Trichloroethylene	<EQL		0.025
75-01-4	Vinyl chloride	<EQL		0.050

SURROGATE	%RECOVERY	LIMITS
1,2-Dichloroethane-d4	103	80 - 130
Toluene-d8	108	88 - 110
4-Bromofluorobenzene	102	85 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-3 Lab No. 03
Test Description TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL		0.50
7440-39-3	Barium	0.787		0.020
7440-43-9	Cadmium	<EQL		0.025
7440-47-3	Chromium	<EQL		0.050
7439-92-1	Lead	<EQL		0.25
7439-97-6	Mercury	<EQL		0.0020
7782-49-2	Selenium	<EQL		0.50
7440-22-4	Silver	<EQL		0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-50-8	Copper	NA		0.10
7440-02-0	Nickel	NA		0.10
7440-66-6	Zinc	NA		0.10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-3 Lab No. 03
Test Description TCLP list pesticides Test Code 8080TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE RUN 06/05/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
57-74-9	Chlordane	<EQL		0.013
72-20-8	Endrin	<EQL		0.0005
76-44-8	Heptachlor and its epoxide	<EQL		0.0003
58-89-9	Lindane	<EQL		0.0003
72-43-5	Methoxychlor	<EQL		0.0024
8001-35-2	Toxaphene	<EQL		0.013

SURROGATE	%RECOVERY	LIMITS
Tetrachloro-m-xylene	97	40 - 160
Decachlorobiphenyl	110	40 - 150

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-3 Lab No. 03
Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL		0.010
93-72-1	2,4,5-TP (Silvex)	<EQL		0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	104	80 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc. Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-3 Lab No. 03
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/10/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutatadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	75	45 - 110
2-Fluorobiphenyl	80	30 - 110
Terphenyl-d14	104	40 - 125
Phenol-d5	70	30 - 110
2-Fluorophenol	63	5 - 125
2,4,6-Tribromophenol	129	45 - 130

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Coal Slurry DES-#1-COMP-3 Lab No. 03
Test Description TCLP list volatiles Test Code 8240TC

ZHE BEGUN 05/29/97 DATE ANALYZED 06/03/97 DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
71-43-2	Benzene	<EQL		0.025
56-23-5	Carbon tetrachloride	<EQL		0.025
108-90-7	Chlorobenzene	<EQL		0.025
67-66-3	Chloroform	<EQL		0.025
107-06-2	1,2-Dichloroethane	<EQL		0.025
75-35-4	1,1-Dichloroethylene	<EQL		0.025
78-93-3	Methyl ethyl ketone	<EQL		0.050
127-18-4	Tetrachloroethylene	<EQL		0.025
79-01-6	Trichloroethylene	<EQL		0.025
75-01-4	Vinyl chloride	<EQL		0.050

SURROGATE	%RECOVERY	LIMITS
1,2-Dichloroethane-d4	101	80 - 130
Toluene-d8	104	88 - 110
4-Bromofluorobenzene	102	85 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc. Reported: 06/12/97

Sample Description Slag DES-#10-Grab-1 Lab No. 07
Test Description TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL	___	0.50
7440-39-3	Barium	0.406	___	0.020
7440-43-9	Cadmium	<EQL	___	0.025
7440-47-3	Chromium	<EQL	___	0.050
7439-92-1	Lead	<EQL	___	0.25
7439-97-6	Mercury	<EQL	___	0.0020
7782-49-2	Selenium	<EQL	___	0.50
7440-22-4	Silver	<EQL	___	0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-50-8	Copper	NA	___	0.10
7440-02-0	Nickel	NA	___	0.10
7440-66-6	Zinc	NA	___	0.10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Slag DES-#10-Grab-1 Lab No. 07
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/10/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	74	45 - 110
2-Fluorobiphenyl	71	30 - 110
Terphenyl-d14	96	40 - 125
Phenol-d5	68	30 - 110
2-Fluorophenol	62	5 - 125
2,4,6-Tribromophenol	119	45 - 130

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Slag DES-#10-Grab-1 Lab No. 07
Test Description TCLP list volatiles Test Code 8240TC

ZHE BEGUN 05/29/97 DATE ANALYZED 06/03/97 DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
71-43-2	Benzene	<EQL		0.025
56-23-5	Carbon tetrachloride	<EQL		0.025
108-90-7	Chlorobenzene	<EQL		0.025
67-66-3	Chloroform	<EQL		0.025
107-06-2	1,2-Dichloroethane	<EQL		0.025
75-35-4	1,1-Dichloroethylene	<EQL		0.025
78-93-3	Methyl ethyl ketone	<EQL		0.050
127-18-4	Tetrachloroethylene	<EQL		0.025
79-01-6	Trichloroethylene	<EQL		0.025
75-01-4	Vinyl chloride	<EQL		0.050

SURROGATE	%RECOVERY	LIMITS
1,2-Dichloroethane-d4	98	80 - 130
Toluene-d8	106	88 - 110
4-Bromofluorobenzene	101	85 - 120

< Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Description Slag DES-#10-Grab-2 Lab No. 08
:s' cription TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL		0.50
7440-39-3	Barium	0.735		0.020
7440-43-9	Cadmium	<EQL		0.025
7440-47-3	Chromium	<EQL		0.050
7439-92-1	Lead	<EQL		0.25
7439-97-6	Mercury	<EQL		0.0020
7782-49-2	Selenium	<EQL		0.50
7440-22-4	Silver	<EQL		0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

7440-50-8	Copper	NA		0.10
7440-02-0	Nickel	NA		0.10
7440-66-6	Zinc	NA		0.10

Sample Description Slag DES-#10-Grab-2 Lab No.. 08

Test Description TCLP list pesticides Test Code 8080TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE RUN 06/05/97

DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
57-74-9	Chlordane	<EQL		0.013
72-20-8	Endrin	<EQL		0.0005
76-44-8	Heptachlor and its epoxide.	<EQL		0.0003
58-89-9	Lindane	<EQL		0.0003
72-43-5	Methoxychlor	<EQL		0.0024
8001-35-2	Toxaphene	<EQL		0.013

SURROGATE	%RECOVERY	LIMITS
Tetrachloro-m-xylene	95	40 - 160
Decachlorobiphenyl	83	40 - 150

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Slag DES-#10-Grab-2 Lab No. 08
Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL	___	0.010
93-72-1	2,4,5-TP (Silvex)	<EQL	___	0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	107	80 - 120

Sample Description Slag DES-#10-Grab-2 Lab No. 08
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/10/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	58	45 - 110
2-Fluorobiphenyl	57	30 - 110
Terphenyl-d14	88	40 - 125
Phenol-d5	53	30 - 110
2-Fluorophenol	49	5 - 125
2,4,6-Tribromophenol	99	45 - 130

Work Order # 97-05-181   Ross Analytical Services, Inc   Reported: 06/12/97

Sample Description Slag DES-#10-Grab-2   Lab No. 08
Test Description TCLP list volatiles   Test Code 8240TC

ZHE BEGUN 05/29/97   DATE ANALYZED 06/02/97   DILUTION FACTOR 1.0   UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
71-43-2	Benzene	<EQL		0.025
56-23-5	Carbon tetrachloride	<EQL		0.025
108-90-7	Chlorobenzene	<EQL		0.025
67-66-3	Chloroform	<EQL		0.025
107-06-2	1,2-Dichloroethane	<EQL		0.025
75-35-4	1,1-Dichloroethylene	<EQL		0.025
78-93-3	Methyl ethyl ketone	<EQL		0.050
127-18-4	Tetrachloroethylene	<EQL		0.025
79-01-6	Trichloroethylene	<EQL		0.025
75-01-4	Vinyl chloride	<EQL		0.050

SURROGATE	%RECOVERY	LIMITS
1,2-Dichloroethane-d4	103	80 - 130
Toluene-d8	108	88 - 110
4-Bromofluorobenzene	102	85 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Slag DES-#10-Grab-3 Lab No. 09
Test Description TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL		0.50
7440-39-3	Barium	0.904		0.020
7440-43-9	Cadmium	<EQL		0.025
7440-47-3	Chromium	<EQL		0.050
7439-92-1	Lead	<EQL		0.25
7439-97-6	Mercury	<EQL		0.0020
7782-49-2	Selenium	<EQL		0.50
7440-22-4	Silver	<EQL		0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-50-8	Copper	NA		0.10
7440-02-0	Nickel	NA		0.10
7440-66-6	Zinc	NA		0.10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97 000035

Sample Description Slag DES-#10-Grab-3 Lab No. 09
Test Description TCLP list pesticides Test Code 8080TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE RUN 06/05/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
57-74-9	Chlordane	≤EQL		0.013
72-20-8	Endrin	≤EQL		0.0005
76-44-8	Heptachlor and its epoxide	≤EQL		0.0003
58-89-9	Lindane	≤EQL		0.0003
72-43-5	Methoxychlor	≤EQL		0.0024
8001-35-2	Toxaphene	≤EQL		0.013

SURROGATE	%RECOVERY	LIMITS
Tetrachloro-m-xylene	95	40 - 160
Decachlorobiphenyl	72	40 - 150

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

000036

Sample Description Slag DES-#10-Grab-3 Lab No. 09
Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL	___	0.010
93-72-1	2,4,5-TP (Silvex)	<EQL	___	0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	112	80 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-1 Lab No. 10
Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/06/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL		0.010
93-72-1	2,4,5-TP (Silvex)	<EQL		0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	112	80 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-1 Lab No. 10
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/10/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	76	45 - 110
2-Fluorobiphenyl	77	30 - 110
Terphenyl-d14	93	40 - 125
Phenol-d5	69	30 - 110
2-Fluorophenol	63	5 - 125
2,4,6-Tribromophenol	116	45 - 130

Sample Description Sulfur DES-#11-GRAB-1 Lab No. 10
Test Description TCLP list volatiles Test Code 8240TC

ZHE BEGUN 05/29/97 DATE ANALYZED 06/03/97 DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
71-43-2	Benzene	<EQL		0.025
56-23-5	Carbon tetrachloride	<EQL		0.025
108-90-7	Chlorobenzene	<EQL		0.025
67-66-3	Chloroform	<EQL		0.025
107-06-2	1,2-Dichloroethane	<EQL		0.025
75-35-4	1,1-Dichloroethylene	<EQL		0.025
78-93-3	Methyl ethyl ketone	<EQL		0.050
127-18-4	Tetrachloroethylene	<EQL		0.025
79-01-6	Trichloroethylene	<EQL		0.025
75-01-4	Vinyl chloride	<EQL		0.050

SURROGATE	%RECOVERY	LIMITS
1,2-Dichloroethane-d4	101	80 - 130
Toluene-d8	107	88 - 110
4-Bromofluorobenzene	103	85 - 120

Sample Description Sulfur DES-#11-GRAB-2 Lab No. 11
Test Description TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL		0.50
7440-39-3	Barium	0.111		0.020
7440-43-9	Cadmium	<EQL		0.025
7440-47-3	Chromium	<EQL		0.050
7439-92-1	Lead	<EQL		0.25
7439-97-6	Mercury	<EQL		0.0020
7782-49-2	Selenium	<EQL		0.50
7440-22-4	Silver	<EQL		0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

7440-50-8	Copper	NA		0.10
7440-02-0	Nickel	NA		0.10
7440-66-6	Zinc	NA		0.10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-2 Lab No. 11
Test Description TCLP list pesticides Test Code 8080TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE RUN 06/05/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
57-74-9	Chlordane	<EQL		0.013
72-20-8	Endrin	<EQL		0.0005
76-44-8	Heptachlor and its epoxide	<EQL		0.0003
58-89-9	Lindane	<EQL		0.0003
72-43-5	Methoxychlor	<EQL		0.0024
8001-35-2	Toxaphene	<EQL		0.013

SURROGATE	%RECOVERY	LIMITS
Tetrachloro-m-xylene	100	40 - 160
Decachlorobiphenyl	110	40 - 150

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-2 Lab No. 11

Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/06/97

DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL	___	0.010
93-72-1	2,4,5-TP (Silvex)	<EQL	___	0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	109	80 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97 000047

Sample Description Sulfur DES-#11-GRAB-2 Lab No. 11
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/11/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	79	45 - 110
2-Fluorobiphenyl	80	30 - 110
Terphenyl-d14	104	40 - 125
Phenol-d5	74	30 - 110
2-Fluorophenol	65	5 - 125
2,4,6-Tribromophenol	130	45 - 130

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-2 Lab No. 11
Test Description TCLP list volatiles Test Code 8240TC

ZHE BEGUN 05/29/97 DATE ANALYZED 06/02/97 DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
71-43-2	Benzene	<EQL		0.025
56-23-5	Carbon tetrachloride	<EQL		0.025
108-90-7	Chlorobenzene	<EQL		0.025
67-66-3	Chloroform	<EQL		0.025
107-06-2	1,2-Dichloroethane	<EQL		0.025
75-35-4	1,1-Dichloroethylene	<EQL		0.025
78-93-3	Methyl ethyl ketone	<EQL		0.050
127-18-4	Tetrachloroethylene	<EQL		0.025
79-01-6	Trichloroethylene	<EQL		0.025
75-01-4	Vinyl chloride	<EQL		0.050

SURROGATE	%RECOVERY	LIMITS
1,2-Dichloroethane-d4	102	80 - 130
Toluene-d8	108	88 - 110
4-Bromofluorobenzene	105	85 - 120

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-3 Lab No. 12

Test Description TCLP list metals Test Code TCMETS

TCLP BEGUN 05/29/97

MERCURY DIGESTED 05/30/97 MERCURY ANALYZED 05/30/97 DILUTION FACTOR 1

OTHER METALS DIGESTED 05/27/97 OTHER METALS ANALYZED 05/30/97 DILUTION FACTOR 1

UNITS mg/L

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-38-2	Arsenic	<EQL		0.50
7440-39-3	Barium	0.158		0.020
7440-43-9	Cadmium	<EQL		0.025
7440-47-3	Chromium	<EQL		0.050
7439-92-1	Lead	<EQL		0.25
7439-97-6	Mercury	<EQL		0.0020
7782-49-2	Selenium	<EQL		0.50
7440-22-4	Silver	<EQL		0.050

Note - Copper, nickel, and zinc are not required by Federal RCRA regulations but are required by some states.

CAS No.	METAL	RESULT	PERCENT RECOVERY	EQL
7440-50-8	Copper	NA		0.10
7440-02-0	Nickel	NA		0.10
7440-66-6	Zinc	NA		0.10

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-3 Lab No. 12
Test Description TCLP list pesticides Test Code 8080TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE RUN 06/05/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
57-74-9	Chlordane	<EQL	___	0.013
72-20-8	Endrin	<EQL	___	0.0005
76-44-8	Heptachlor and its epoxide	<EQL	___	0.0003
58-89-9	Lindane	<EQL	___	0.0003
72-43-5	Methoxychlor	<EQL	___	0.0024
8001-35-2	Toxaphene	<EQL	___	0.013

SURROGATE	%RECOVERY	LIMITS
Tetrachloro-m-xylene	110	40 - 160
Decachlorobiphenyl	130	40 - 150

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

Sample Description Sulfur DES-#11-GRAB-3 Lab No. 12
Test Description TCLP list semivolatiles Test Code 8270TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 05/30/97 DATE ANALYZED 06/10/97
DILUTION FACTOR 1 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
	Total cresols	<EQL		0.30
106-46-7	1,4-Dichlorobenzene	<EQL		0.10
121-14-2	2,4-Dinitrotoluene	<EQL		0.10
118-74-1	Hexachlorobenzene	<EQL		0.10
87-68-3	Hexachlorobutatadiene	<EQL		0.10
67-72-1	Hexachloroethane	<EQL		0.10
98-95-3	Nitrobenzene	<EQL		0.10
87-86-5	Pentachlorophenol	<EQL		0.50
110-86-1	Pyridine	<EQL		0.10
95-95-4	2,4,5-Trichlorophenol	<EQL		0.10
88-06-2	2,4,6-Trichlorophenol	<EQL		0.10

SURROGATE	%RECOVERY	LIMITS
Nitrobenzene-d5	69	45 - 110
2-Fluorobiphenyl	67	30 - 110
Terphenyl-d14	99	40 - 125
Phenol-d5	64	30 - 110
2-Fluorophenol	58	5 - 125
2,4,6-Tribromophenol	116	45 - 130

Work Order # 97-05-181 Ross Analytical Services, Inc Reported: 06/12/97

000051

Sample Description Sulfur DES-#11-GRAB-3 Lab No. 12
Test Description TCLP list herbicides Test Code 8150TC

TCLP BEGUN 05/29/97 DATE EXTRACTED 06/02/97 DATE ANALYZED 06/09/97
DILUTION FACTOR 1.0 UNITS mg/L

CAS No.	COMPOUND	ANALYTICAL RESULT	PERCENT RECOVERY	EQL
94-75-7	2,4-D	<EQL		0.010
93-72-1	2,4,5-TP (Silvex)	<EQL		0.010

SURROGATE	%RECOVERY	LIMITS
2,4-DB	103	80 - 120